EXECUTIVE OFFICES

**INTERMOUNTAIN GAS COMPANY**

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IDAHO PUBLIC
UTILITIES COMMISSION

January 13, 2015

Ms. Jean Jewell
Idaho Public Utilities Commission
472 W. Washington Street
P.O. Box 83720
Boise, ID 83720-0074

RE: Intermountain Gas Company's 2015 Integrated Resource Plan
Case No. INT-G-15-01

Dear Ms. Jewell:

Enclosed for filing with this Commission are the original and seven (7) copies of Intermountain Gas Company's 2015 Integrated Resource Plan.

If you have any questions or require additional information regarding the attached, please contact me at 377-6168.

Very truly yours,

Michael P. McGrath
Director – Regulatory Affairs

Enclosures

cc: Scott Madison

# INTERMOUNTAIN GAS COMPANY

## INTEGRATED RESOURCE PLAN

## 2015 – 2019



INTERMOUNTAIN®
GAS COMPANY
*A Subsidiary of MDU Resources Group, Inc.*

***In the Community to Serve®***

**January 2015**

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# Integrated Resource Plan

# EXECUTIVE SUMMARY

Natural gas continues to be the fuel of choice in Idaho. Southern Idaho's manufacturing plants, commercial businesses, new homes and anticipated new electric power plants, all rely on natural gas to provide an economic, efficient, environmentally friendly, comfortable form of heating energy. Intermountain Gas Company ("Intermountain" or "IGC") endorses and encourages the wise and efficient use of energy in general and, in particular, natural gas for high efficient uses in Idaho and Intermountain's service area. Forecasting the demand of Intermountain's growing customer base is a regular part of Intermountain's operations, as is determining how to best meet the load requirements brought on by this demand. Public input is an integral part of this planning process. The customer demand forecast and resource decision making process is ongoing. This Integrated Resource Plan ("IRP") document represents a snapshot in time similar to a balance sheet. It is not meant to be a prescription for all future energy resource decisions, as conditions will change over the planning horizon impacting areas covered by this Plan. Rather, this document is meant to describe the currently anticipated conditions over the five-year planning horizon, the anticipated resource selections and the process for making resource decisions. The planning process described herein is an integral part of Intermountain's ongoing commitment to make the wise and efficient use of natural gas an important part of Idaho's energy future.

## Backdrop

Intermountain is the sole distributor of natural gas in Southern Idaho. Its service area extends across the entire breadth of Southern Idaho, an area of 50,000 square miles, with a population of approximately 1,000,000. During the first half of 2013, Intermountain served an average of 321,500 customers in 73 communities through a system of over 10,000 miles of transmission, distribution and service lines. Over 149 miles of distribution and service lines were added during 2013 to accommodate new customer additions and maintain service for Intermountain's growing customer base.

The economy of Intermountain's service area is based primarily on agriculture and related industries. Major crops are potatoes and sugar beets. Major agricultural-related industries include food processing and production of chemical fertilizers. Other significant industries are electronics, general manufacturing and services and tourism.

Intermountain provides natural gas sales and service to two major markets: the residential/commercial market and the industrial market. During 2013, an average of 290,500 residential and 31,000 commercial customers used natural gas primarily for space and water heating, compared to an average of 285,300 residential and 30,500 commercial customers in 2008. This equates to an increase in average residential and commercial customers of 1.8%.

Intermountain's industrial customers transport natural gas through Intermountain's system to be used for boiler and manufacturing applications. Industrial demand for natural gas is strongly influenced by the agricultural economy and the price of alternative fuels. 44% of the throughput on Intermountain's system during 2013 was attributable to industrial sales and transportation.

## Forecast Peak Day Sendout

## Total Company

Residential, commercial and industrial peak day load growth on Intermountain's system under design conditions is forecast over the five-year period to grow at an average annual rate of 2.32% under the base case scenario. The table below summarizes the forecast for peak day sendout under the base case customer growth assumption.

**LOAD DURATION CURVE - TOTAL COMPANY DESIGN BASE CASE**

(Volumes in Therms)

| | NWP Firm Transport Capacity[1] | Peak Day Sendout | | | Incremental Peak Day Sendout | | |
|---|---|---|---|---|---|---|---|
| | | Core Market | Industrial Firm CD | Total | Core Market | Industrial Firm CD[2] | Total |
| FY15 | 4,848,820 | 3,848,290 | 46,580 | 3,894,870 | | | |
| FY16 | 4,848,820 | 3,928,440 | 46,580 | 3,975,020 | 80,150 | 0 | 80,150 |
| FY17 | 4,848,820 | 4,018,280 | 46,580 | 4,064,860 | 89,840 | 0 | 89,840 |
| FY18 | 4,848,820 | 4,119,770 | 46,580 | 4,166,350 | 101,490 | 0 | 101,490 |
| FY19 | 4,848,820 | 4,222,060 | 46,580 | 4,268,640 | 102,290 | 0 | 102,290 |

[1]See Peak Day Firm Delivery Capability table on page 4

[2]Future growth in transport CD is limited to T-4, which does not affect Intermountain's interstate pipeline capacity requirements.

The above table highlights the fact that growth in the peak day is commensurate with the growth projected to occur in Intermountain's residential and small commercial customer markets.

## Existing Resources:

Intermountain's existing firm delivery capability on the peak day is made up of the resources shown on the following page.

**PEAK DAY FIRM DELIVERY CAPABILITY**

**(Volumes in Therms)**

| | FY15 | FY16 | FY17 | FY18 | FY19 |
|---|---|---|---|---|---|
| **Maximum Daily Storage Withdrawals:** | | | | | |
| **Nampa LNG** | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 |
| **Plymouth LS** | 1,132,000 | 1,132,000 | 1,132,000 | 1,132,000 | 1,132,000 |
| **Jackson Prairie SGS** | 303,370 | 303,370 | 303,370 | 303,370 | 303,370 |
| **Total Storage** | 2,035,370 | 2,035,370 | 2,035,370 | 2,035,370 | 2,035,370 |
| **Maximum Deliverability (NWP)** | 2,813,450 | 2,813,450 | 2,813,450 | 2,813,450 | 2,813,450 |
| **Total Peak Day Deliverability** | 4,848,820 | 4,848,820 | 4,848,820 | 4,848,820 | 4,848,820 |

When forecasted peak day sendout is matched against existing resources, there are no peak day delivery deficits.

**FIRM DELIVERY DEFICIT – TOTAL COMPANY DESIGN BASE CASE**

(Volumes in Therms)

| | FY15 | FY16 | FY17 | FY18 | FY19 |
|---|---|---|---|---|---|
| Peak Day Deficit [1] | 0 | 0 | 0 | 0 | 0 |
| Total Winter Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Days Requiring Additional Resources | 0 | 0 | 0 | 0 | 0 |

[1]Equal to demand less all available supply and delivery resources.

## Regional Studies

Certain geographic regions within Intermountain's service territory were analyzed based upon the anticipated or potential need for distribution system upgrades within each specific region. Not unlike the total company interstate mainline perspective, the projected peak day sendout for each region was measured against the known distribution capacity and resources available to serve that region. In addition to the firm delivery requirements for Intermountain's residential and commercial customers, the needs of those industrial customers contracting for firm distribution only transportation service (Intermountain's "T-4" customers) were also included as part of these regional studies. A wide array of alternatives were evaluated in formulating the best plan to meet the projected deficits in the various regions within Intermountain's service territory (see "Non-Traditional Resource Options" - Page 71).

Additionally, each region is analyzed within the framework of the Company's Distribution System Model (See Page 76).

## IDAHO FALLS LATERAL

The Idaho Falls Lateral ("IFL") is 104 miles in length and serves a number of cities between Pocatello in the south and St. Anthony in the north. The customers served by the IFL represent a diverse base of residential, commercial and large industrial customers. The residential, commercial and industrial load served off the IFL represents approximately 16% of the total company customers and 14% of the company's projected peak day sendout during January of 2015.

When forecasted peak day sendout on the IFL is matched against the existing IFL peak day capacity, all peak day demands can be met over the FY15 through FY19 forecast period:

**LOAD DURATION CURVE - IDAHO FALLS DESIGN BASE CASE**

(Volumes in Therms)

| | Distribution | Peak Day Sendout | | | Incremental Peak Day Sendout | | |
|---|---|---|---|---|---|---|---|
| | Transport Capacity[1] | Core Market | Industrial Firm CD[2] | Total | Core Market | Industrial Firm CD[3] | Total |
| FY15 | 1,240,000 | 693,110 | 234,700 | 927,810 | | | |
| FY16 | 1,240,000 | 707,860 | 234,770 | 942,560 | 14,750 | 0 | 14,750 |
| FY17 | 1,240,000 | 725,680 | 234,770 | 960,380 | 17,820 | 0 | 17,820 |
| FY18 | 1,240,000 | 744,730 | 234,770 | 979,430 | 19,050 | 0 | 19,050 |
| FY19 | 1,240,000 | 763,880 | 234,770 | 998,580 | 19,150 | 0 | 19,150 |

[1]Includes Rexburg LNG Facility for peak day shaving @ 282,000 peak day therms.

[2]Existing firm contract demand includes T-4 and T-5 requirements.

[3]Future growth in transport CD is limited to T-4 which only impacts Intermountain's distribution capacity requirements.

**FIRM DELIVERY DEFICIT - IDAHO FALLS DESIGN BASE CASE**

(Volumes in Therms)

| | FY15 | FY16 | FY17 | FY18 | FY19 |
|---|---|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Total Winter Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Days Requiring Additional Resources | 0 | 0 | 0 | 0 | 0 |

[1]Equal to demand less all available supply and delivery resources.

The IFL currently has a portable LNG facility in Rexburg that will be utilized as a peak shaving device to meet customer demands and supplement firm capacity on the lateral during peak day events. The additional capacity from Rexburg LNG is planned for use in 2017, 2018 and 2019.

## SUN VALLEY LATERAL

The residential, commercial and industrial load served off the Sun Valley Lateral ("SVL") represents approximately 4% of the total company customers and 4% of the company's projected peak day sendout during January of 2015.

When forecasted peak day sendout on the Sun Valley Lateral is matched against the existing peak day distribution capacity (202,000 therms), a peak day delivery deficit does not occur during this IRP period. See table on the following page:

**LOAD DURATION CURVE - SUN VALLEY DESIGN BASE CASE**

(Volumes in Therms)

| | Distribution Transport Capacity | Peak Day Sendout Core Market | Industrial Firm CD[1] | Total | Incremental Peak Day Sendout Core Market | Industrial Firm CD[2] | Total |
|---|---|---|---|---|---|---|---|
| **FY15** | 202,000 | 164,000 | 13,350 | 177,350 | | | |
| **FY16** | 202,000 | 165,770 | 13,350 | 179,120 | 1,770 | 0 | 1,770 |
| **FY17** | 202,000 | 167,950 | 13,350 | 181,300 | 2,180 | 0 | 2,180 |
| **FY18** | 202,000 | 170,130 | 13,350 | 183,480 | 2,180 | 0 | 2,180 |
| **FY19** | 202,000 | 172,320 | 13,350 | 185,670 | 2,190 | 0 | 2,190 |

[1]Existing firm contract demand includes T-4 and T-5 requirements.

[2]Future growth in transport CD is limited to T-4 which only impacts Intermountain's distribution capacity requirements.

**FIRM DELIVERY DEFICIT - SUN VALLEY DESIGN BASE CASE**

(Volumes in Therms)

| | FY15 | FY16 | FY17 | FY18 | FY19 |
|---|---|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Total Winter Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Days Requiring Additional Resources | 0 | 0 | 0 | 0 | 0 |

[1]Equal to demand less all available supply and delivery resources.

## CANYON COUNTY REGION

The residential, commercial and industrial load in the Canyon County Region ("CCR") represents approximately 15% of the total company customers and 14% of the company's projected peak day sendout during January of 2015.

When forecasted peak day sendout for the Canyon County Region is matched against the existing peak day distribution capacity (790,000 therms), a peak day delivery deficit does not occur during this IRP period. See table below:

**LOAD DURATION CURVE - CANYON COUNTY DESIGN BASE CASE**

(Volumes in Therms)

| | Distribution Transport Capacity | Peak Day Sendout Core Market | Peak Day Sendout Industrial Firm CD[1] | Peak Day Sendout Total | Incremental Peak Day Sendout Core Market | Incremental Peak Day Sendout Industrial Firm CD[2] | Incremental Peak Day Sendout Total |
|---|---|---|---|---|---|---|---|
| **FY15** | 790,000 | 558,300 | 126,510 | 684,810 | | | |
| **FY16** | 790,000 | 574,490 | 126,510 | 701,000 | 16,190 | 0 | 16,190 |
| **FY17** | 790,000 | 593,160 | 126,510 | 719,670 | 18,670 | 0 | 18,670 |
| **FY18** | 790,000 | 603,710 | 126,510 | 730,220 | 10,550 | 0 | 10,550 |
| **FY19** | 790,000 | 638,350 | 126,510 | 764,860 | 34,640 | 0 | 34,640 |

[1] Existing firm contract demand includes T-4 and T-5 requirements.

[2] Future growth in transport CD is limited to T-4 which only impacts Intermountain's distribution capacity requirements.

**FIRM DELIVERY DEFICIT - CANYON COUNTY DESIGN BASE CASE**

(Volumes in Therms)

| | FY15 | FY16 | FY17 | FY18 | FY19 |
|---|---|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Total Winter Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Days Requiring Additional Resources | 0 | 0 | 0 | 0 | 0 |

[1] Equal to demand less all available supply and delivery resources.

While diverse in nature, the industrial customer base served within the CCR does not currently have the capability to switch to alternative fuels as a means of mitigating peak day sendout and Intermountain is currently exploring optional means of enhancing the distribution capability in this area.

## STATE STREET LATERAL

The State Street Lateral ("SSL") is 16.2 miles in length and serves a number of customers in the NW Boise area. The customers served by the State Street lateral represent a base of primarily residential and commercial customers. The residential and commercial load served off the SSL represents approximately 14% of the total company customers and 12% of the company's projected peak day sendout during January of 2015.

When forecasted peak day sendout on the SSL is matched against the existing peak day distribution capacity (644,000 therms – 2016 and 695,000 therms - 2017), a peak day delivery deficit does not occur during this IRP period. See table below:

**LOAD DURATION CURVE – STATE STREET DESIGN BASE CASE**

(Volumes in Therms)

| | Distribution Transport Capacity | Peak Day Sendout Core Market | Peak Day Sendout Industrial Firm CD[1] | Peak Day Sendout Total | Incremental Peak Day Sendout Core Market | Incremental Peak Day Sendout Industrial Firm CD[2] | Incremental Peak Day Sendout Total |
|---|---|---|---|---|---|---|---|
| **FY15** | 644,000 | 575,820 | 16,700 | 592,520 | | | |
| **FY16** | 644,000 | 587,870 | 16,700 | 604,570 | 12,050 | 0 | 12,050 |
| **FY17** | 695,000 | 600,530 | 16,700 | 617,230 | 12,660 | 0 | 12,660 |
| **FY18** | 695,000 | 615,250 | 16,700 | 631,950 | 14,720 | 0 | 14,720 |
| **FY19** | 695,000 | 630,100 | 16,700 | 646,800 | 14,850 | 0 | 14,850 |

[1]Existing firm contract demand includes T-4 and T-5 requirements.

[2]Future growth in transport CD is limited to T-4 which only impacts Intermountain's distribution capacity requirements.

**FIRM DELIVERY DEFICIT – STATE STREET DESIGN BASE CASE**

(Volumes in Therms)

| | FY15 | FY16 | FY17 | FY18 | FY19 |
|---|---|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Total Winter Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Days Requiring Additional Resources | 0 | 0 | 0 | 0 | 0 |

[1]Equal to demand less all available supply and delivery resources.

## CENTRAL ADA AREA

The Central Ada Area ("CAA") is comprised of 24 miles of high pressure pipeline and serves a number of customers in the Boise area. The customers served in this area represent a diverse base of residential and commercial customers. The residential and commercial load served within the area represent approximately 15% of the total company customers and 12% of the company's total projected peak day sendout during January of 2015.

When forecasted peak day sendout from the CAA is matched against the existing peak day distribution capacity (625,000 therms – 2016 and 702,000 therms - 2017), a peak day delivery deficit does not occur during this IRP period. See table below:

**LOAD DURATION CURVE – CENTRAL ADA DESIGN BASE CASE**

(Volumes in Therms)

| | Distribution | Peak Day Sendout | | | Incremental Peak Day Sendout | | |
|---|---|---|---|---|---|---|---|
| | Transport Capacity | Core Market | Industrial Firm CD[1] | Total | Core Market | Industrial Firm CD[2] | Total |
| FY15 | 625,000 | 599,420 | 10,100 | 609,520 | | | |
| FY16 | 625,000 | 613,630 | 10,100 | 623,730 | 14,210 | 0 | 14,210 |
| FY17 | 702,000 | 628,630 | 10,100 | 638,730 | 15,000 | 0 | 15,000 |
| FY18 | 702,000 | 646,080 | 10,100 | 656,180 | 17,450 | 0 | 17,450 |
| FY19 | 702,000 | 663,690 | 10,100 | 673,190 | 17,610 | 0 | 17,610 |

[1]Existing firm contract demand includes T-4 and T-5 requirements.

[2]Future growth in transport CD is limited to T-4 which only impacts Intermountain's distribution capacity requirements.

**FIRM DELIVERY DEFICIT – CENTRAL ADA DESIGN BASE CASE**

(Volumes in Therms)

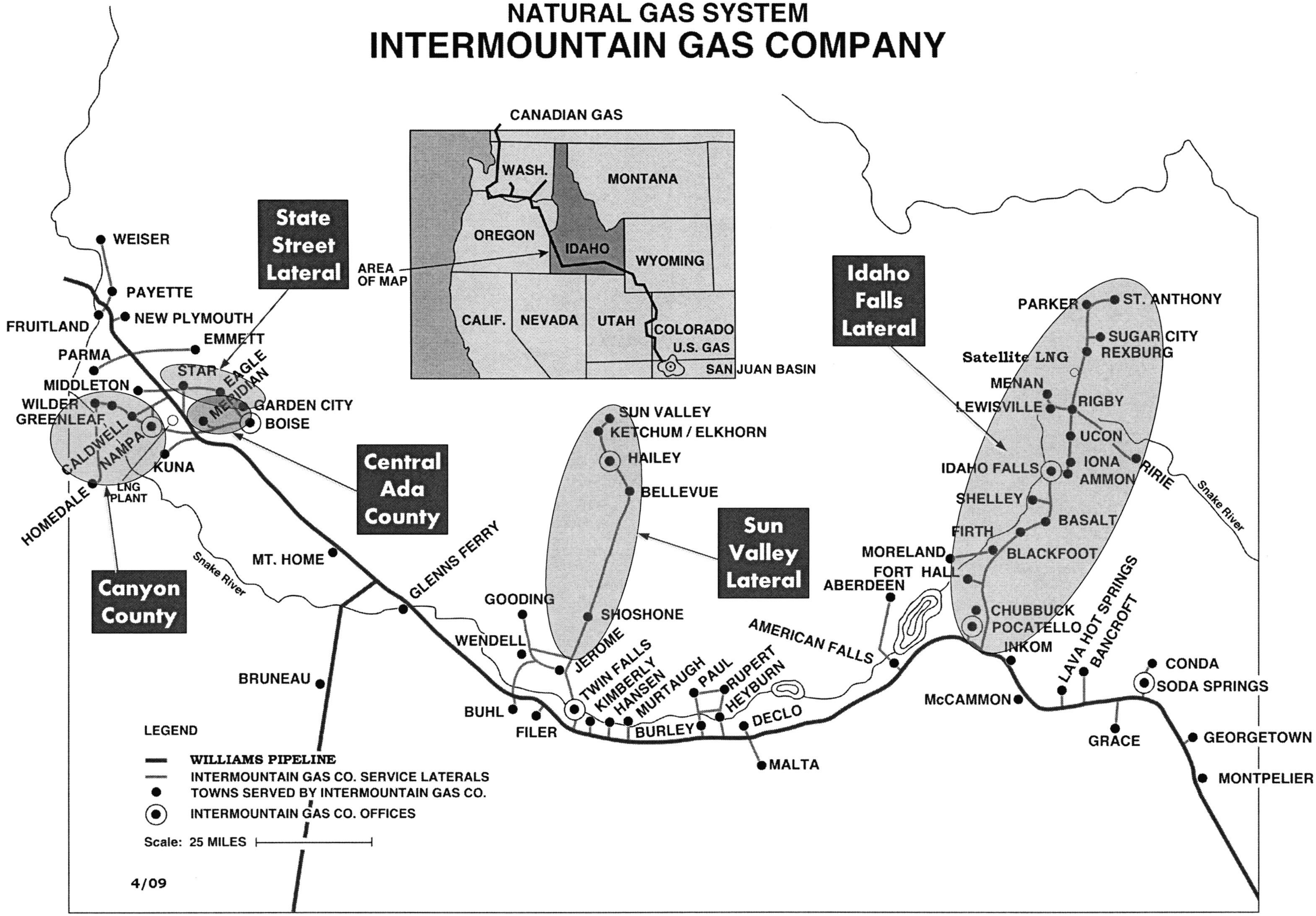
| | FY15 | FY16 | FY17 | FY18 | FY19 |
|---|---|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Total Winter Deficit[1] | 0 | 0 | 0 | 0 | 0 |
| Days Requiring Additional Resources | 0 | 0 | 0 | 0 | 0 |

[1]Equal to demand less all available supply and delivery resources.

## Summary

Residential, commercial and industrial customer growth and their consequent impact on Intermountain's distribution system have been analyzed using design weather conditions under various scenarios for Idaho's economy. Peak day sendout under each of these customer growth scenarios was measured against the available natural gas delivery systems to project the magnitude and timing of potential delivery deficits, both from a total company perspective as well as a regional perspective. The resources needed to meet these projected deficits were analyzed within a framework of options, both traditional and non-traditional, to help determine the most cost-effective means available to manage the deficits. In utilizing these options, Intermountain's core market and firm transportation customers can continue to rely on uninterrupted firm service both now and in the years to come.

# NATURAL GAS SYSTEM
# INTERMOUNTAIN GAS COMPANY



# DEMAND FORECAST OVERVIEW

The first step in resource planning is forecasting future load requirements. Three essential components of the load forecast include projecting the number of customers requiring service, forecasting the weather sensitive customers' response to temperatures and estimating the weather those customers may experience. To complete the demand forecast, contracted maximum deliveries to industrial customers are also included.

Intermountain's long range demand forecast incorporates various factors including divergent customer forecasts, statistically based gas usage per customer calculations, varied weather profiles and banded natural gas price projections (all of which are fully discussed further in this document.) Using various combinations of these factors results in six separate and diverse demand forecast scenarios for the weather sensitive core market customers.

Combining those projections with the industrial market forecast provides Intermountain with six total company demand scenarios that envelop a wide range of potential outcomes. These forecasts not only project monthly and annual loads but also predict daily usage including peak demand events. The inclusion of all this detail allows Intermountain to evaluate the adequacy of its supply arrangements and delivery under a wide range of demand scenarios.

Intermountain's resource planning looks at distinct segments (also known as Areas of Interest or AOI's) within its current distribution system. After analyzing resource requirements at the segment level, the data is aggregated to provide a Total Company perspective. The AOI's for planning purposes are as follows:

- The Canyon County Segment, which consists of the Core Market Customers in Canyon County.
- The Sun Valley Lateral Segment, consisting of the Core Market Customers in Blaine and Lincoln Counties.
- The Idaho Falls Lateral Segment, consisting of the Core Market Customers in Bingham, Bonneville, Fremont, Jefferson, and Madison Counties, along with approximately 29% of the Core Market Customers in Pocatello, Bannock County.
- The Central Ada County Lateral Segment ("Central Ada") consisting of the area of Ada County between Chinden Boulevard and Victory Road, north to south, and between Maple Grove Road and Black Cat Road, east to west.. This segment is newly-defined and included in this 2014 IRP.
- The "North of State Street" Lateral Segment, ("State Street") consisting of the area of Ada County north of the Boise River, bound on the west by Kingsbury Road west of Star, and bound on the east by State Highway 21.
- The All Other Customers Segment, consisting of the Core Market Customers in Ada County not included in the State Street and Central Ada segments, Bear Lake, Caribou, Cassia, Elmore, Gem, Gooding, Jerome, Minidoka, Owyhee, Payette, Power, Twin Falls, and Washington Counties. Additionally, 71% of the Core Market Customers in Pocatello, Bannock County, as well as the rest of Bannock County, are included in this segment

# RESIDENTIAL AND COMMERCIAL CUSTOMER GROWTH FORECAST

This section of the Intermountain Gas Company's Integrated Resource Plan describes and summarizes the residential and commercial customer growth forecast for the years 2015 through 2019. This forecast provides the anticipated magnitude and direction of IGC's residential and small customer growth by the aforementioned IGC Distribution System Segments for IGC's current service territory. Customer growth is the primary driving factor in IGC's five-year demand forecast contained within IGC's IRP.

IGC's customer growth forecast includes three (3) key components:

1. Residential New Construction Customers,
2. Residential Customers who convert to natural gas from an alternative fuel, and
3. Small Commercial Customers

The residential customers are divided into two groups – RS-1 customers, who do not have at least a natural gas furnace providing main heat for the home <u>and</u> a natural gas water heater. The other group, RS-2 customers, do have at least a natural gas furnace providing main heat for the home <u>and</u> a natural gas water heater.

To calculate the number of customers added each year, the annual change in households for each county in the IGC Service Territory is determined using the <u>Idaho Economics Winter 2014 Economic Forecast for the State of Idaho</u> by John S. Church ("'14 Forecast"), dated February 2014. Using the assumption that a new household means a new dwelling is needed, the annual change in households by county is multiplied by IGC's market penetration rate in that region to determine the additional residential new construction customers. Next, that number is multiplied by the IGC conversion rate, which is the anticipated percentage of conversion customers relative to new construction customers in those locales. This results in the number of expected residential conversion customers, and when added to the residential new construction numbers, the total expected additional residential customers across the periods is derived, by county.

To accurately estimate growth for the State Street segment, which contains a small portion of Canyon County in addition to the major portion entirely in Ada County, an additional estimate was made for that segment after the total Ada County forecast was derived. Using the 2012 COMPASS growth forecast for Ada County, the forecast growth in the Traffic Analysis Zones (TAZ) in the State Street segment was compared to the overall forecast growth for all of Ada County. This was calculated to be 34% for RS-1 customers, 31% for RS-2 customers, and 34% for GS customers. This was used as the base for estimating the forecast growth in the State Street segment.

The Central Ada segment sits entirely in Ada County. A similar methodology to that described above for the State Street segment was used to derive the percentage of overall Ada County growth for RS-1, RS-2, and GS customers. This was calculated to be 31% for RS-1 customers, 38% for RS-2 customers, and 31% for GS customers.

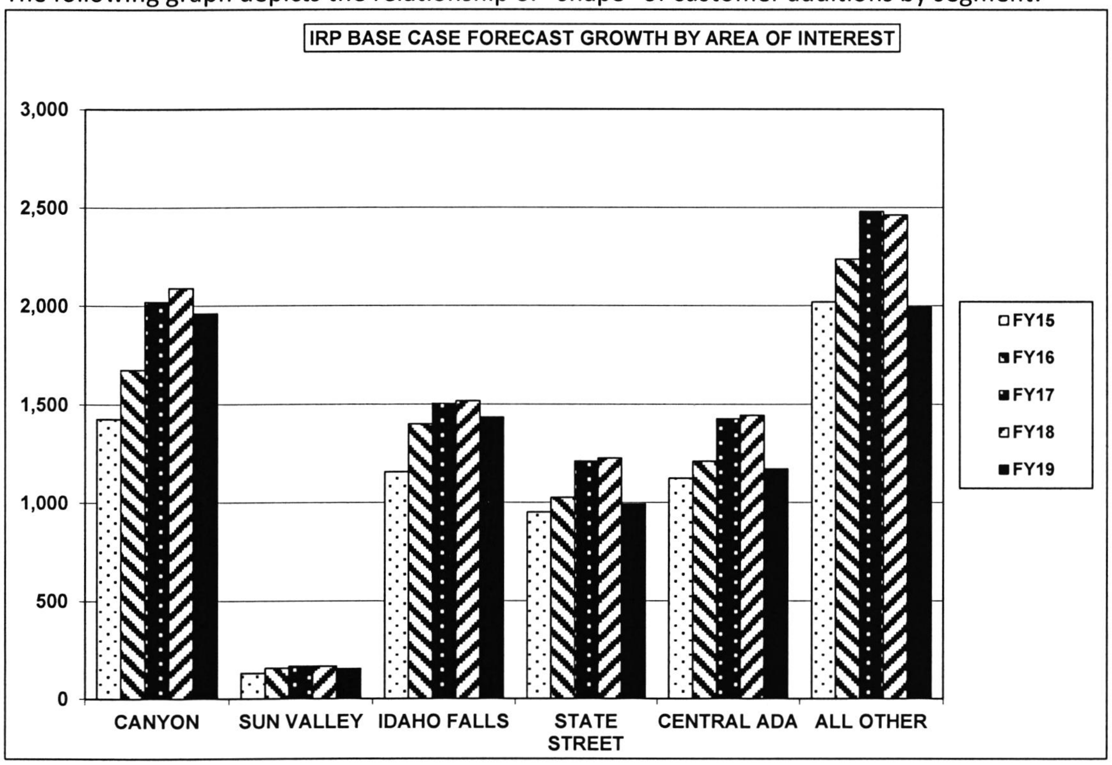
The residential new construction numbers by county are multiplied by the IGC commercial rate, which is the anticipated percentage of commercial customers relative to residential new construction customers in those locales, to arrive at the number of expected additional small commercial customers.

The residential numbers must be split across our two residential rate classes, RS-1 and RS-2, since these classes have different load patterns. As mentioned above, RS-1 is a customer who does not have both a gas furnace and a gas water heater, regardless of other appliances. RS-2 customers have at least a gas furnace and a gas water heater. Virtually 100% of IGC's residential new construction customers go RS-2, while only regionally varying percentages of IGC's residential conversion customers go RS-2. So, the additional residential conversion customers are split, depending on the region.

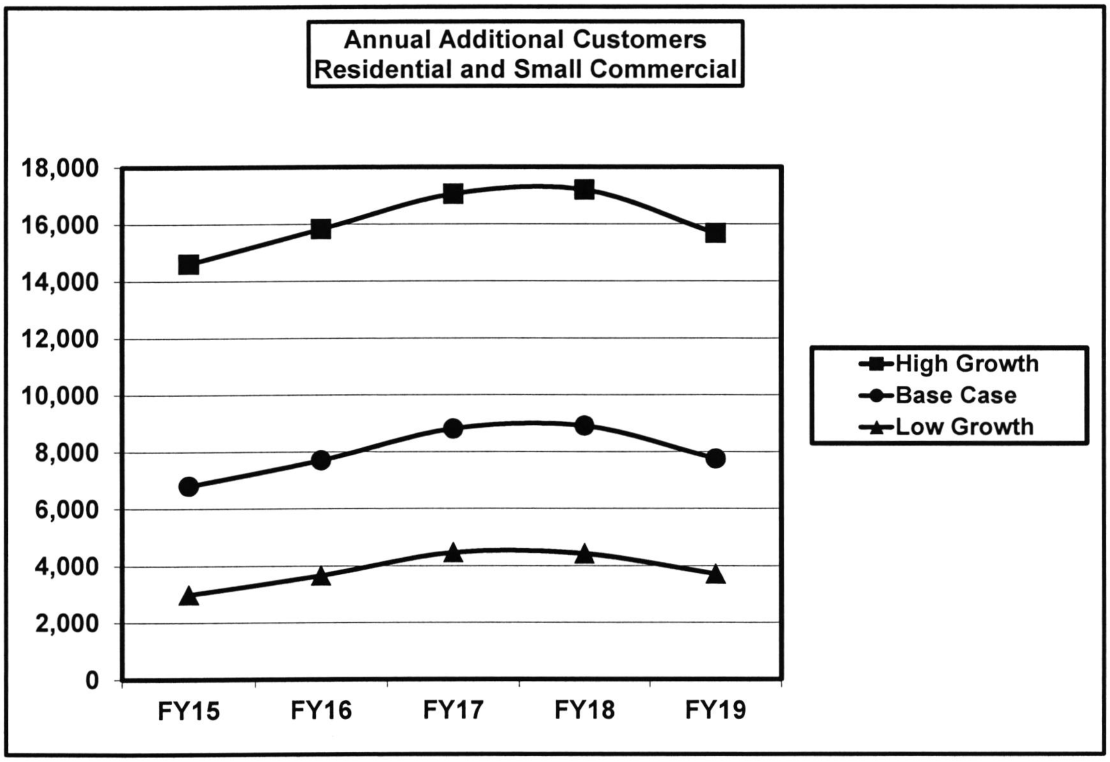
With the recent upturn in the housing market, IGC growth projections are up considerably, when compared to the 2012 IRP. The '14 Forecast household numbers are employed to determine the relative overall number of customer additions, as well as the distribution of those customer additions, that is, the location of additional customers within our system.

In addition to the forecast methodologies just described, IGC surveyed municipalities and counties to ascertain their outlooks for growth over the IRP period. This information was compared to our forecasts for correlation and relevance. None of the survey data compelled any adjustment to our forecasts, but the inclusion of the municipal and county viewpoints was very valuable, and will be incorporated in future IRP's. A sample of the municipal/county survey forms and the mailing list used to send the surveys is at Exhibit 1 Appendix G.

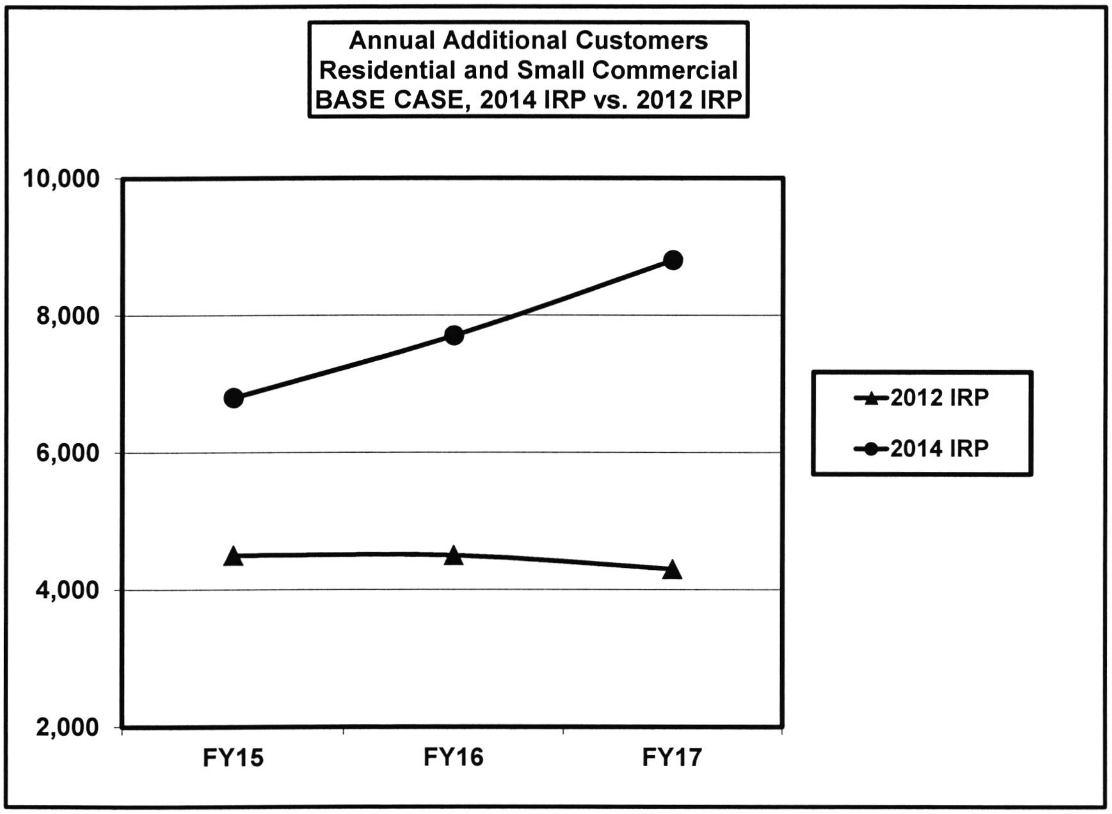
The following graph depicts the relationship or "shape" of customer additions by segment:




The '14 Forecast contains three economic scenarios: base case, low growth, and high growth. IGC has incorporated these scenarios into the customer growth model, and has developed three five-year core market customer growth forecasts. The following graph shows the annual additional customers for each of the three economic scenarios.




The following graph shows the difference in base case annual additional customers between the 2012 and 2014 IRP forecast years common to both studies:




As indicated, the economic recovery, and its resulting positive impact on housing and business growth has resulted in a much increased IGC customer growth forecast in the years common to the 2012 and 2014 IRP's.

The following table shows the results from the 5-year customer growth model for each scenario for the total customers at each year-end, and the annual additional or incremental, customers:

| | TOTAL CUSTOMERS | | ANNUAL ADDITIONAL CUSTOMERS | |
|---|---|---|---|---|
| | Range as a % Of Base Case | Average as a % of Base Case | Range as a % Of Base Case | Average as a % of Base Case |
| Low Growth | 94% - 99% | 97% | 44% - 51% | 48% |
| Baseline | 100% - 100% | 100% | 100% - 100% | 100% |
| High Growth | 102% - 111% | 107% | 193% - 215% | 202% |
| | Range (2015 – 2019) | Average | Range (2015 – 2019) | Average |
| Low Growth | 335,725 – 351,959 | 343,829 | 2,985 – 4,460 | 3,844 |
| Baseline | 339,540 – 372,639 | 356,079 | 6,800 – 8,900 | 7,990 |
| High Growth | 347,340 – 413,097 | 380,242 | 14,600 – 17,195 | 16,067 |

The following sections explore, more fully, the different components of the customer forecast, including the '14 Forecast, market penetration and conversion rates, and small commercial growth.

## HOUSEHOLD PROJECTIONS / CHURCH FORECAST

The Idaho Economics Winter 2014 Economic Forecast for the State of Idaho by John S. Church ('14 Forecast), provides county by county projections of output, employment and wage data for 21 industry categories for the State of Idaho, as well as a population and household forecast. This simultaneous equation model uses personal income and employment by industry as the main economic drivers of the forecast. This model uses forecasts of national inputs and demands for those sectors of the Idaho economy having a national or international exposure. Industries that do not have as large a national profile, and are thus serving local communities and demands are considered secondary industries. Local economic factors, rather than the national economy determine demand for these products.

The '14 Forecast uses two methods for population projections: (1) a cohort-component population model in which annual births and deaths are forecast, and then the net number is either added to or subtracted from the population; and (2) an econometric model which forecasts population as a function of economic activity. The two forecasts are then compared and reconciled for each quarter of the forecast. Migration into or out of the state is arrived at in this reconciliation.

As previously mentioned, the '14 Forecast provides three scenarios: (1) baseline, (2) high growth, and (3) low growth. The baseline scenario assumes a normal amount of economic fluctuation, a normal business cycle. This becomes the standard against which changes in customer growth, as affected by the low and high growth scenarios can be measured.

### The Base Case Economic Growth Scenario

In the Base Case Scenario of the '14 Forecast, it is projected that Idaho will continue to be an attractive environment for population and household growth. In the decade of the 1990s Idaho's population increased at an annual average rate of 2.5% per year.

The national recession brought a significant slowdown in Idaho's job growth during the 2000 to 2010 period and a decline in the rate of population growth -- slowing to an annual average rate of 1.9% per year over the decade. Nevertheless, that rate of population growth was higher than Idaho's annual average rate of natural population growth (births minus deaths) of nearly 1.0% per year, indicating that Idaho continued to attract an in-migration of population even during tough economic times.

In the 2010 to 2040 thirty year forecast period it is anticipated that Idaho's population will increase by 808,400 persons, reaching a total population of 2,380,000 by the year 2040 -- an annual average pace of 1.4% per year over the thirty-year period. The number of households in the state is expected to increase at a slightly faster pace of 1.6% per year over the 2010 to 2040 period adding nearly 364,000 additional households statewide.

Ada and Canyon Counties are projected to capture the lion's share of the state's future population growth over the 2010 to 2040 forecast period. Ada County is projected see a population increase of 339,000 (144,200 households) in the 2010 to 2040 period. Canyon County will take up 2nd place statewide, with a projected population increase of 171,100 (a 68,400 increase in the number of households). In Eastern Idaho, Bonneville, Madison, Bannock, and Jefferson counties are expected to see increases in population of 54,200, 31,800, 21,600 and 19,800, respectively, over the 2010 to 2040 forecast period.

In the Base Case Scenario of '14 Forecast, it is assumed that Idaho will continue to be an attractive environment for new businesses. Therefore, in spite of the employment losses that the State has experienced in the recent economic downturn, Idaho's industries regain some economic traction, and continue to expand in the future.

Total Non-Agricultural employment in the state is projected to increase by nearly 125,500 over the 2010 to 2020 period. Ada and Canyon Counties will capture the majority of those job gains with non-ag employment projected to increase by 67,300 in the 2010 to 2020 period. In the longer-term 2010 to 2040 thirty-year period, non-ag employment statewide is projected to increase by 286,000 - an annual average pace of 1.3% per year. Again, Ada and Canyon counties are projected to capture the lion's share of job growth over the 30- year period - 181,300 jobs or 63.3% of the projected non-ag employment gains statewide.

The counties along the Idaho Falls Lateral (Bannock, Bingham, Bonneville, Butte, Fremont, Jefferson, Madison, and Power) are projected to see non-ag employment increase by 55,200 over the 2010 to 2040 period - 19.3% of the statewide non-ag job gains.

The Twin Falls area (Blaine, Camas, Cassia, Gooding, Jerome, Lincoln, Minidoka, and Twin Falls counties) is projected to experience an increase of 23,900 non-ag jobs over the 2010 to 2040 period -- 8.3% of the projected statewide gain in non-ag employment.

In contrast to previous economic forecasts, the manufacturing sector will not be the driver of economic growth in the state. From 2000 to 2010, manufacturing employment in the state decreased by 17,200 jobs. It is projected that the state will regain 13,300 of those jobs in the 2010 to 2020 period. In the longer term, manufacturing employment in the state is projected to increase by only 6,700 jobs in the 2010 to 2040 period - an annual average increase of 0.4%.

Ada and Canyon counties are projected to capture 4,400 of those manufacturing job gains in the state. Most of those manufacturing job gains over the 2010 to 2040 period are expected to be in machinery and electronic equipment manufacturing.

From 1990 to 2010, food processing employment in Ada and Canyon Counties had been increasing - largely on the strength of job gains in the dairy products manufacturing sector. In the forecast period it is expected that the dairy products manufacturing firms will continue to post job gains. At the same time, it is expected that vegetable processing firms in Ada and Canyon Counties will experience significant job losses over the 2010 to 2040 forecast period. The net effect of these trends in the food processing industry is that the food processing sector will not be a significant contributor to manufacturing job gains in Ada and Canyon counties.

On the other hand, the food processing industry is projected to be the main driver behind the projected gains of 1,300 manufacturing jobs in the Twin Falls area over the 2010 to 2040 period.

Employment in Idaho's Lumber and Wood Products manufacturing industry slipped in the last recession. Future job gains in the Lumber and Wood Products manufacturing sector are projected to be minimal over the 2010 to 2040 forecast period. Statewide employment in Stone, Clay, and Glass Products and Fabricated Metal Products manufacturing is expected to increase in proportion to population and household growth in the state.

Employment in Idaho's Electronics and Machinery manufacturing sectors is expected to partially regain some of the jobs lost during the last recession. However, in the base scenario of the '14 Forecast, employment in these two manufacturing industries are not anticipated to recover to prerecession levels, and no new electronics plants are assumed in the 2010 to 2040 forecast period.

Employment in the Transportation, Trade, and Utilities industries is projected to increase by nearly 29,400 jobs over the 2010 to 2040 forecast period - an annual increase of 0.7%. In general, employment in the Transportation, Trade, and Utilities industries is projected to increase at a pace that tracks the rate of population and household growth statewide.

Over the 2010 to 2040 forecast period Ada and Canyon counties will capture 19,100 of the Transportation, Trade, and Utilities jobs in the state -- 65.0% of the projected job gains statewide. The counties along the Idaho Lateral are projected to see gains of 6,000 jobs in the Transportation, Trade, and Utilities industries -- 20.4% of the projected statewide gains in these industries.

Over the 2010 to 2040 forecast period, the Service industries are projected to be the sectors that will add the greatest amount of jobs. Professional and Business Services employment statewide is projected to increase by nearly 75,000 over the 30 year forecast period. Employment in Education and Health Services is projected to add 74,600 jobs statewide. The Leisure and Hospitality Services sectors are projected to add 35,900 jobs over the forecast period.

Even with the tight fiscal conditions that came with the last recession, employment in the Government sector of the Idaho economy increased by nearly 9,700 during the 2000 to 2010 period. The '14 Forecast projects that government employment statewide will increase by another 9,700 over the 2010 to 2020 period. Thereafter, growth in government employment in the state will regain some momentum, and increase by nearly 13,300 during the 2020 to 2030 period before slowing again in the 2030s.

Over the thirty year forecast it is projected that government employment statewide will increase by nearly 31,300 - an annual average pace of 0.8%. Generally, the bulk of the increase in government employment will be in the state and local government area, and will largely be associated with the need for additional local government employees to provide basic services to a growing population in the state.

It is again projected that Ada and Canyon Counties will capture the majority (16,800 jobs) of the projected government job gains statewide over the 2010 to 2040 period.

The Base Case '14 Forecast for the State of Idaho and its 44 counties is for a slightly more optimistic economic outlook compared to that forecast in the June 2011 Church Forecast ('11 Forecast). While Idaho's economy is slowly recovering, employment numbers are expected to post a slightly reduced growth rate through the IRP period.

In the '14 Forecast, non-agricultural employment in Idaho is projected to grow at an annual rate of 1.91% over the 2015 – 2019 IRP period. This is a lower rate than the 2.28% annual growth rate projected in the '11 Forecast. As described above, the non-ag jobs total in the '14 Forecast ranges from 9,000 to 13,000 fewer jobs fewer than projected in the '11 Forecast.

Manufacturing employment exhibits similar behavior. The 2014 IRP-period annual growth rate here is 0.75% compared to a 2.1% rate in the '11 Forecast. On the other hand, the '14 Forecast annual Manufacturing totals exceed the annual '11 Forecast figures by 1,100 to 1,900 jobs, a 1.7 – 2.1% lead.

Projections of the 2014 IRP-period population growth in Idaho remain fairly consistent in the '14 Forecast compared to the '11 Forecast. In the newer forecast, Idaho's total population is forecasted to grow from the estimated 2015 figure of 1,658,001 to 1,772,696 by 2019, an annual growth rate of 1.66%. In the older forecast, Idaho's total population was forecasted to grow from the estimated 2013 figure of 1,618,000 to 1,767,530 by 2017, an annual growth rate of 1.79%. The number of future households projected in the State is slightly higher in the '14 Forecast.

## The High and Low Economic Growth Scenarios

The High-Growth and Low-Growth Scenarios of the '14 Forecast present alternative views of the economic future of Idaho and its 44 counties. The High Growth Scenario of the Economic Forecast presents a vision of a more- rapidly growing economy in Idaho. For example, the High Growth Scenario produces a projected statewide population of 1,866,815 in the year 2019 versus a Base Scenario Idaho population forecast of 1,772,696 in the same year. The High Growth scenario average annual compound rate of population growth is 2.41% per year.

Alternatively, the Low Growth Scenario of the '14 Forecast presents a slower economic outlook for the Idaho economy. In the Low Growth Scenario, Idaho's 2016 population is projected to reach the much lower level of 1,660,265, exhibiting an annual average compound growth rate of 0.70% per year.

An examination of the possible economic and demographic events that could produce the economic and population growth projected in the High and Low Growth Scenarios is outlined below:

By the year 2040, the High Case Scenario forecast of population and number of households in Idaho is 11.3% higher than the Base Case. This represents nearly 268,600 more people in the State by the year 2040, and nearly 106,000 additional households. The projected gap between the High Case Scenario and the Base Case Scenarios widens by the years 2020 and 2030. In 2020 and 2030 the forecasted population of Idaho in the High Case Scenario is projected to be nearly 109,200 and 189,800 more, respectively, than that predicted in the Base Case Scenario.

Similarly, the forecasted number of Idaho households in the High Case Scenario is greater than the Base Case Forecast by 41,200 in the year 2020, and 72,400 more than the Base Case in the year 2030.

In the High Case Scenario it is projected that stronger employment gains statewide will be a magnet for a stronger rate of in-migration to the state. It is assumed that Idaho will be a modestly more attractive environment for manufacturing firms. Therefore, in spite of the employment losses that the State has experienced in this economic downturn Idaho's manufacturing industries are expected to add an additional 2,600 jobs in manufacturing over the 2010 to 2040 forecast period when compared to the Base Scenario Forecast.

It is assumed in the High Case Scenario that the Food Processing industry does not lose as many jobs as in vegetable processing facilities across the state, and that Idaho will attract a new electronics manufacturing plant in the Boise area that will employ nearly 2,000 persons.

It is expected that employment in Lumber and Wood Products manufacturing, Transportation Equipment manufacturing, and Machinery manufacturing will not benefit from the stronger-growth Idaho economy of the High Case Scenario.

Transportation, Trade, and Utilities employment in the High Case Scenario is projected to be nearly 9,700 jobs (6.4%) greater by the year 2040 than in the Base Case Scenario. The High Case Scenario increases in Transportation Industry employment are expected to occur in Idaho's air transportation sector. Growth in air transportation employment in Boise will accelerate, and that a long-rumored regional air-freight hub will be established at the Bose Air Terminal. In addition, a new airport for Wood River Valley will be completed. This new, larger, and safer, airport facility will attract increased air transportation activity not only directly to the Wood River Valley, but also indirectly with connecting flights to Boise.

In addition, the Communications and Utilities sectors are expected to see higher levels of employment in the High Case Scenario. In both the Communications and Utilities industries, a large portion of this projected increase in employment is in reaction to faster population and household growth in the State of Idaho.

However, another component of this projected higher level of employment is the assumed continuation of the growth in the Communications industry's "call center" facilities in Idaho (T-Mobile, and others) and the continued expansion of independent electric power production facilities, including wind farms.

Trade industry employment in the High Case Scenario is projected to be nearly 7,000 jobs (6.2%) jobs greater by the year 2040 than in the Base Scenario. Service industry employment in the High Case is projected to be even more robust than in the already strong outlook found in the Base Case. In the High Case Scenario the outlook for employment in the Service industries is projected to be nearly 23,800 jobs (7.8%) greater than the Base Case by the year 2020, and 50,800 jobs (16.7%) and 60,600 jobs (19.9%) higher than the Base Case Scenario by the years 2030 and 2040, respectively. Again a large portion of this difference is due to the higher levels of population and household growth anticipated in the High Case Scenario.

Hotel and motel accommodations and activities are also classified in the Service industry category. The High Scenario forecast assumes that tourism-related or recreational travel in Idaho increases, and as a result, employment in the lodging and recreation sectors also increases. In the High Case the shuttered Tamarack Resort is assumed to recover from its current state of closure and will flourish under a new future ownership.

The Service industry outlook in the High Case assumes that, there is a portion, roughly one-half, of the projected higher level of service industry employment that is caused by the relocation of firms new to Idaho. The Federal Reserve Bank of San Francisco speculates that a portion of the strong economic growth that is currently being experienced in Arizona, Nevada, New Mexico, Oregon, Utah, and Idaho is due to an outmigration of population and businesses from California. Their studies have shown that many small California firms have concluded that the cost of doing business in California has become too great for them to remain competitive. Therefore, an increasing number of these firms are making decisions to relocate close to, but outside of, California. Hence, the very rapid growth occurring in Nevada, Arizona, and to a lesser extent, southern Oregon. Currently, New Mexico, Utah, and Idaho are capturing only a small portion of that exodus. The High Case assumes that this trend continues and that Idaho, over time, captures a larger share of those relocation decisions.

Federal Government employment in the High Case Scenario is projected to be nearly unchanged from the Base Case by the year 2020, and 800 jobs greater after the year 2020. It is assumed in the High Case Scenario that the number of assigned personnel at Mountain Home Air Force Base will be about 2,000 higher than under the Base Case. The number of military personnel does not normally show up in the state's total employment figures.

It is further assumed in the High Case that Mining industry employment in North Idaho's silver mines will be nearly 500 greater than the in the Base Case. In general, Construction, Natural Resources, and Mining industry employment in the High Case is expected to be nearly 1,800 jobs higher than in the Base Case. With the exception of the assumed gains in the Mining industry mentioned above, this higher level of employment is in the Construction industry, and is due to the projected higher level of population and population growth.

In the Low Case Scenario forecast of population and number of households in Idaho is 11.3 percent lower than the Base Case figures by the year 2040. This represents nearly 297,800 fewer people in the State by then, and nearly 128,500 fewer households.

The projected gap between the Low Case and the Base Case Scenarios widens by the years 2020 and 2030, when the forecasted population of Idaho in the Low Case is projected to be nearly 130,600 and 282,500 fewer, respectively, than that predicted in the Base Case Scenario.

Similarly, the forecasted number of Idaho households in the Low Case is lower than in the Base Case by 49,300 in the year 2020, and 109,300 fewer than in 2030. It is also projected that slower employment gains statewide will attract a low level of population in-migration.

Idaho's Manufacturing employment in the Low Case does not recover from the last recession over the 2010 - 2040 forecast period. Similarly, the State's loss of jobs in the Food Processing industry accelerates, and nearly 1,200 additional jobs are lost over the same forecast period. The potato processing plants in Southern Idaho experience the bulk of these job losses. For example, it is assumed in the Low Case that the JR Simplot plant in Caldwell would lose close to 1,000 jobs over the next five years. It is further assumed in the Low Case that the sugar processing industry in Southern Idaho would also feel increased pressure from competition, and would find it necessary to close one of the sugar processing plants in Nampa, Paul, or Twin Falls, Idaho.

The dairy industry and its associated food processing plants would reach a point where no further capacity could be added due to increased population and environmental pressures.

Employment losses in Idaho's Lumber and Wood Products manufacturing industry are assumed to accelerate in the Low Case. The brunt of these additional losses would be felt in those portions of the wood products industry that could be increasingly vulnerable to low-cost foreign-produced products, such as the Woodgrain molding plants in Fruitland and Nampa, Idaho.

Idaho's Electronics and Machinery manufacturing industries would experience further job losses over the forecast period. Employment in Stone, Clay, and Glass Products, as well as the Fabricated Metal Products manufacturing industries are both projected to be at lower levels of total employment than in the Base Case. Overall, Manufacturing-industry employment in the year 2040 is nearly 5,800 jobs, or 9.7% lower than in the Base Case.

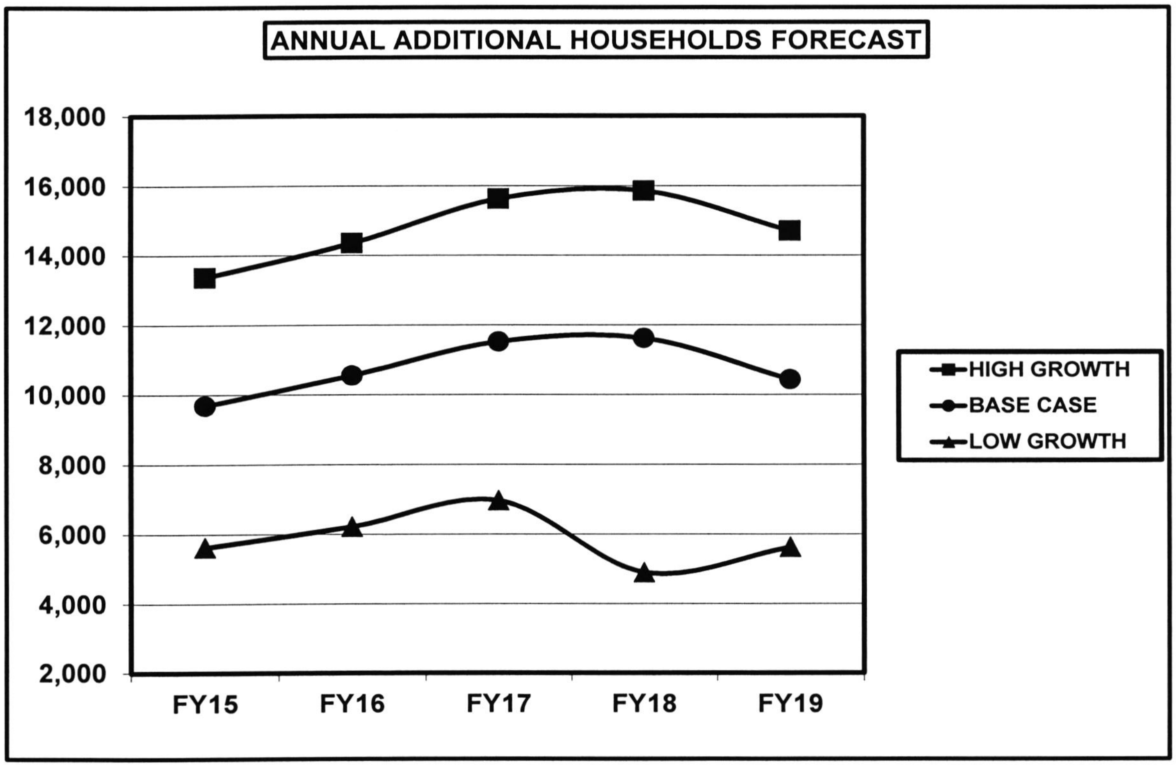
Transportation, Trade, and Utilities employment in the Low Case is projected to have nearly 4,200, or 2.8% fewer jobs than the Base Case by 2040. The lower overall economic growth inherent in the Low Case produces lower demand for transportation services and for the buying opportunities of additional Trade industry facilities. The Low Case also assumes that some of the State's food processing facilities will close, reducing the need for large amounts of truck transportation.

Wholesale and Retail Trade industry employment in the Low Case is projected to be nearly 2,400 jobs lower than in the Base Case by 2040. The difference in Trade industry employment is due to the lower levels of population and household growth.

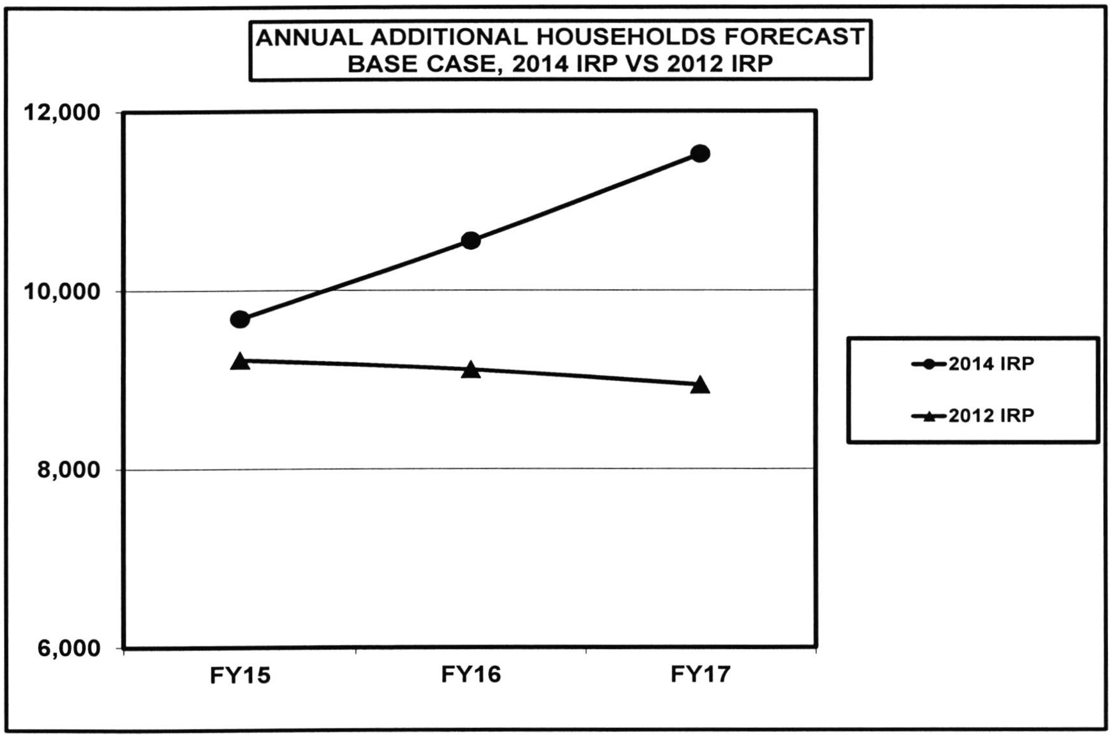
The Low Case forecast of employment in the Finance, Insurance, and Real Estate sector is about 1,500 jobs lower than in the Base Case by 2040. Again, the difference is largely due to the lower levels of population and household growth.

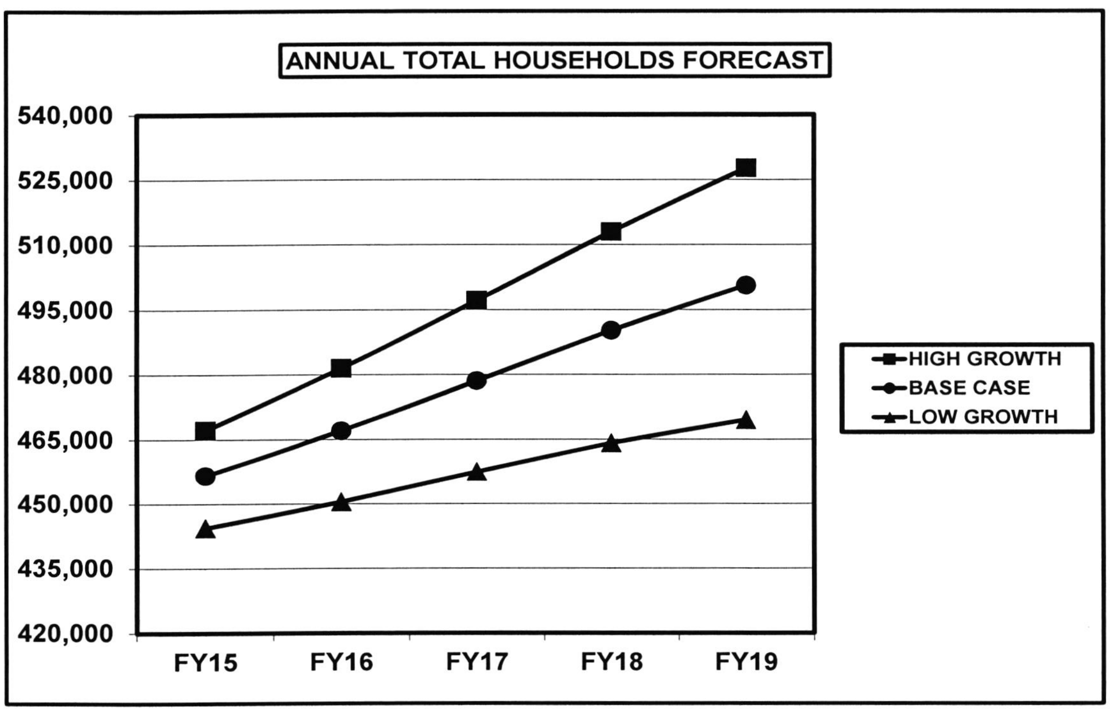
The outlook for the Service industry outlook in the Low Case also assumes that employment growth in the Service sector slows with the projected slower growth in population and households statewide. And, it is assumed that Idaho is less attractive to those Service industry firms from outside Idaho that may have considered relocating to Idaho. Idaho's competitive position for attractive new business is degraded, and the nearby states of Utah, Oregon, and Nevada capture a larger proportion of firms making relocation and expansion decisions.

Future Government employment in the Low Case is projected to be 16,200 jobs or 1.6% lower than the Base Case by 2040. As in other aforementioned areas lower levels of projected Government employment in the Low Case is the result of slower rates of population and household growth. It is assumed in the Low Case that Mountain Home Air Force Base will maintain a level of activity that is similar to the present time.

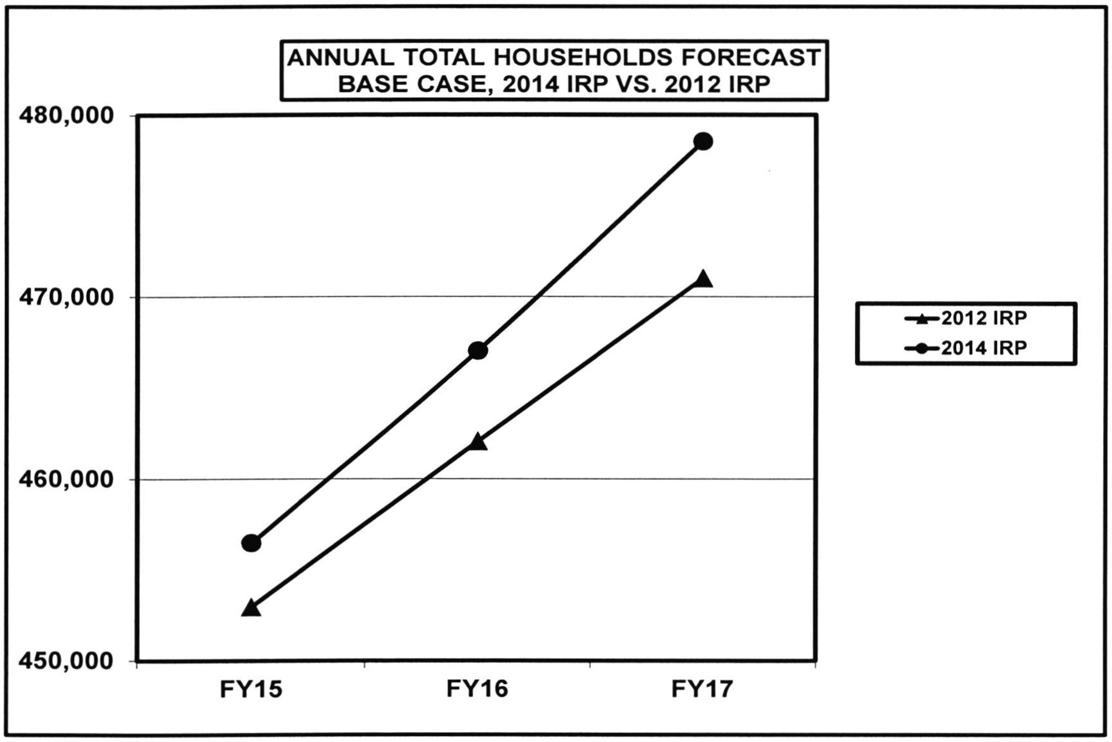


The following graph shows the difference in base case annual additional households between the 2012 and 2014 IRP forecast years common to both studies:



The following graph shows the difference in base case total households between the 2012 and 2014 IRP forecast years common to both studies:




## MARKET SHARE RATES

IGC utilizes market penetration rates that vary across the service territory. These regional penetration rates are applied to the IGC service-territory counties within the three specific regions: west, central, and east. These penetration rates are the ratio of IGC's additional residential new construction customers to the total building permits in those regions. The forecast additional households, per the Church Forecast, multiplied by the regional market penetration rate equals the anticipated residential new construction customers.

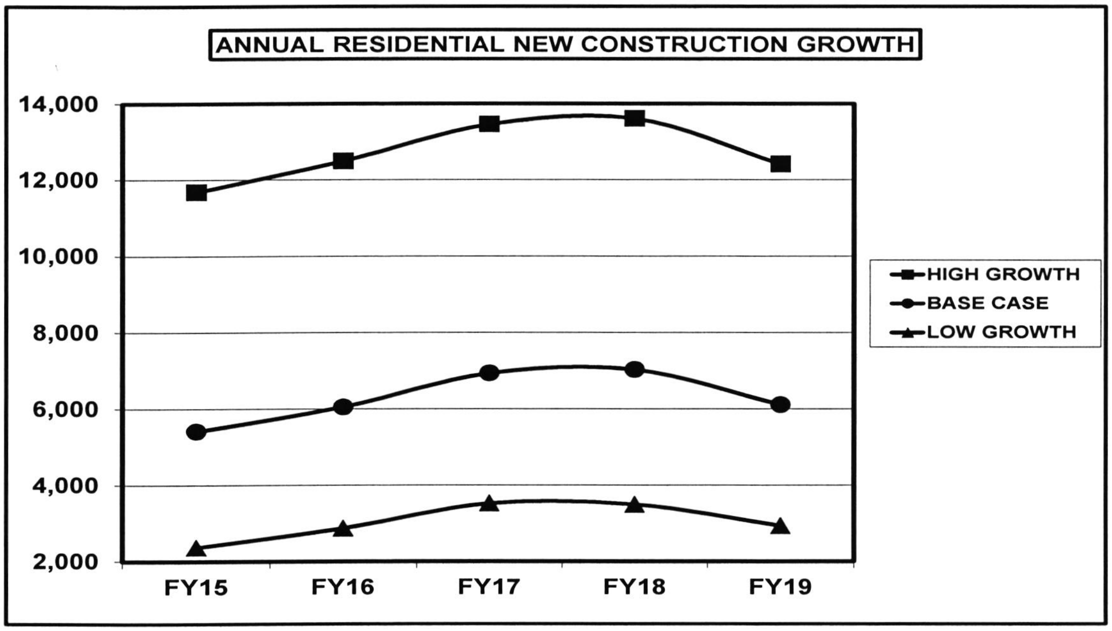
IGC develops market penetration rates by way of the county construction reports which IGC marketing and construction personnel use in prospecting for new construction customers. The residential new construction sales in the specific areas covered by these reports are divided by the total dwellings listed in these reports, to derive the market penetration rate. The areas covered here are the major population centers in the IGC Service Territory: Ada/Canyon County, Twin Falls/Wood River Valley, Pocatello/Soda Springs, and Idaho Falls/Rexburg. These rates are derived month by month.

The market penetration rates used in the customer forecasting varied somewhat when going into the future out of anticipated market share gains in the Central and Eastern regions. Those for the West remained relatively static through the forecast period, since they are already near 100%. The same set of market penetration rates was used in the baseline, high growth, and low growth scenarios.

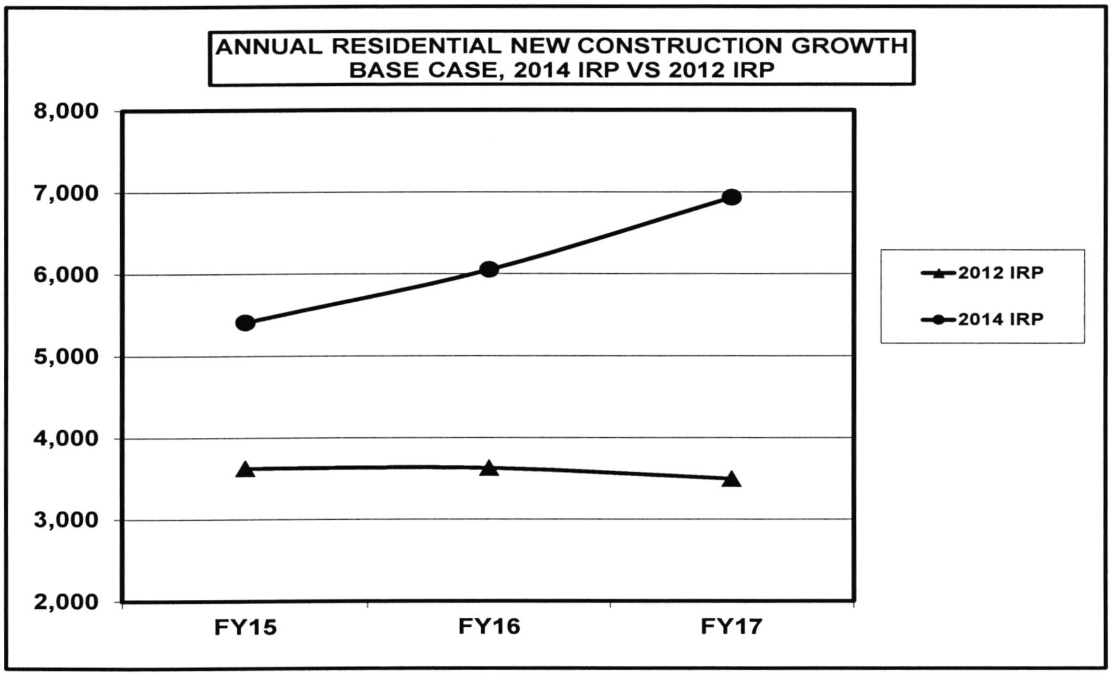
**MARKET PENETRATION RATES**

| | FY15 | FY16 | FY17 | FY18 | FY19 |
|---|---|---|---|---|---|
| Western Region | 98% | 98% | 98% | 98% | 98% |
| Central Division | 90% | 91% | 92% | 92% | 92% |
| Eastern Region | 70% | 75% | 80% | 80% | 80% |

The following graph illustrates the relationship between the three economic scenarios for the annual residential new construction growth forecast for 2015 – 2019:



The following graph shows the difference in base case residential new construction customer growth between the '12 and '14 IRP forecast years common to both studies:



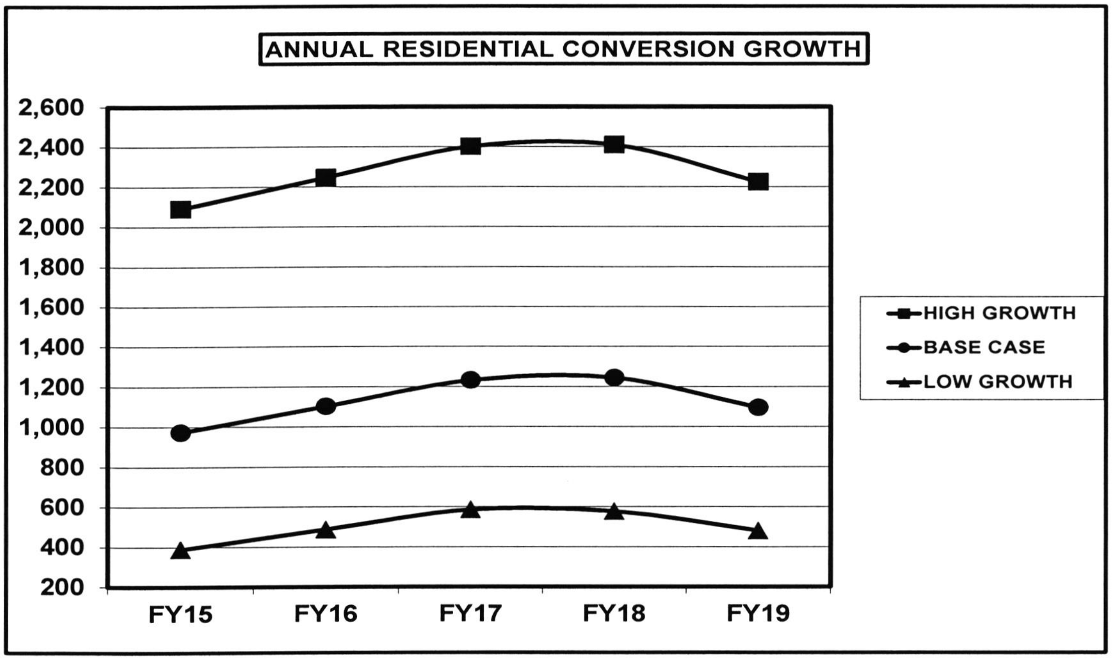

## CONVERSIONS

The conversion market represents another source of customer growth. IGC acquires these customers when homeowners replace an electric, oil, coal, wood, or other alternate fuel source furnace/water heater with a natural gas unit. IGC forecasts these customer additions by applying regional conversion rates based on historical data and future expectations. The following table shows, by region the assumed conversion rates over the five-year period. These rates represent the percentage of new construction additions which will be conversions.

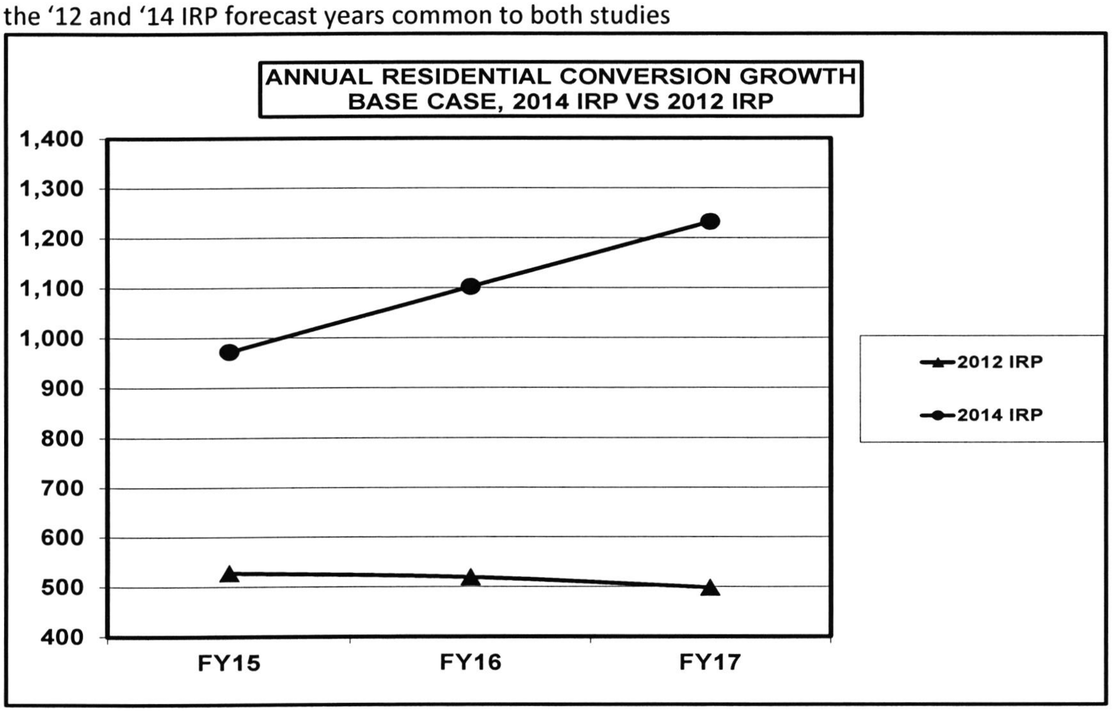
## REGIONAL CONVERSION RATES

| | FY15 | FY16 | FY17 | FY18 | FY19 |
|---|---|---|---|---|---|
| **Western Region** | | | | | |
| Base Case | 13% | 13% | 13% | 13% | 13% |
| High Growth | 13% | 13% | 13% | 13% | 13% |
| Low Growth | 13% | 13% | 13% | 13% | 13% |
| **Central Region** | | | | | |
| Base Case | 30% | 30% | 30% | 30% | 30% |
| High Growth | 30% | 30% | 30% | 30% | 30% |
| Low Growth | 30% | 30% | 30% | 30% | 30% |
| **Eastern Division** | | | | | |
| Base Case | 31% | 31% | 31% | 31% | 31% |
| High Growth | 31% | 31% | 31% | 31% | 31% |
| Low Growth | 31% | 31% | 31% | 31% | 31% |

The following graphs illustrate the relationship between the three economic scenarios for the annual residential conversion growth forecast for 2015 – 2019:



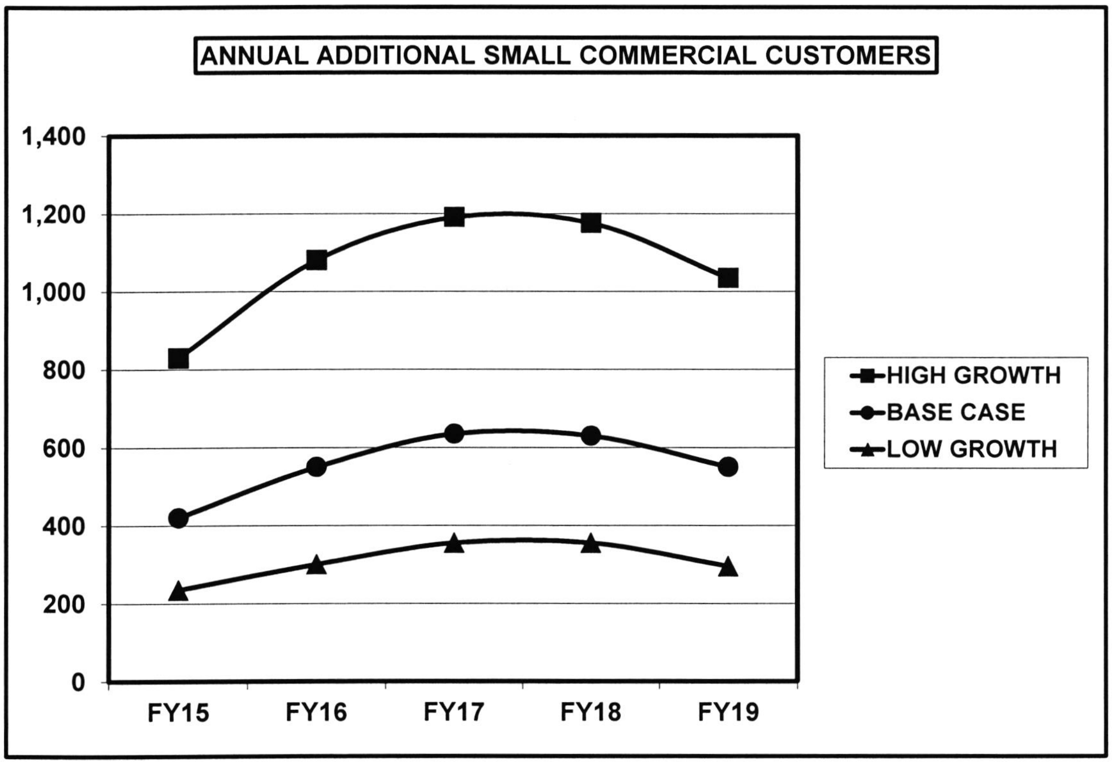

The following graph shows the difference in base case residential conversion customer growth between the '12 and '14 IRP forecast years common to both studies

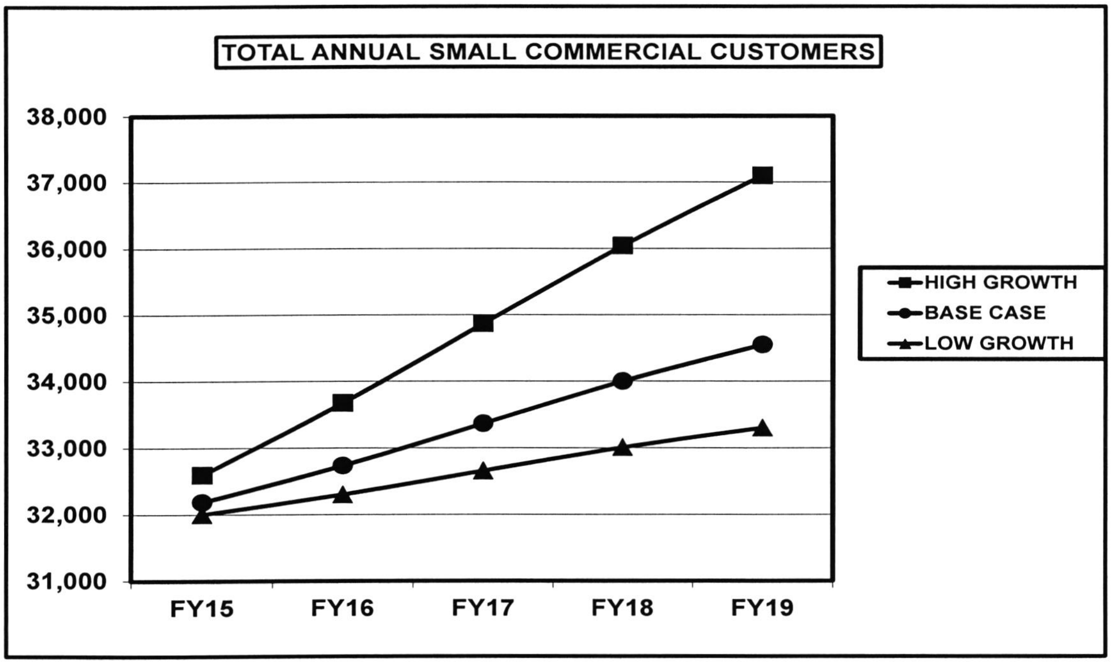


## Small Commercial Customers

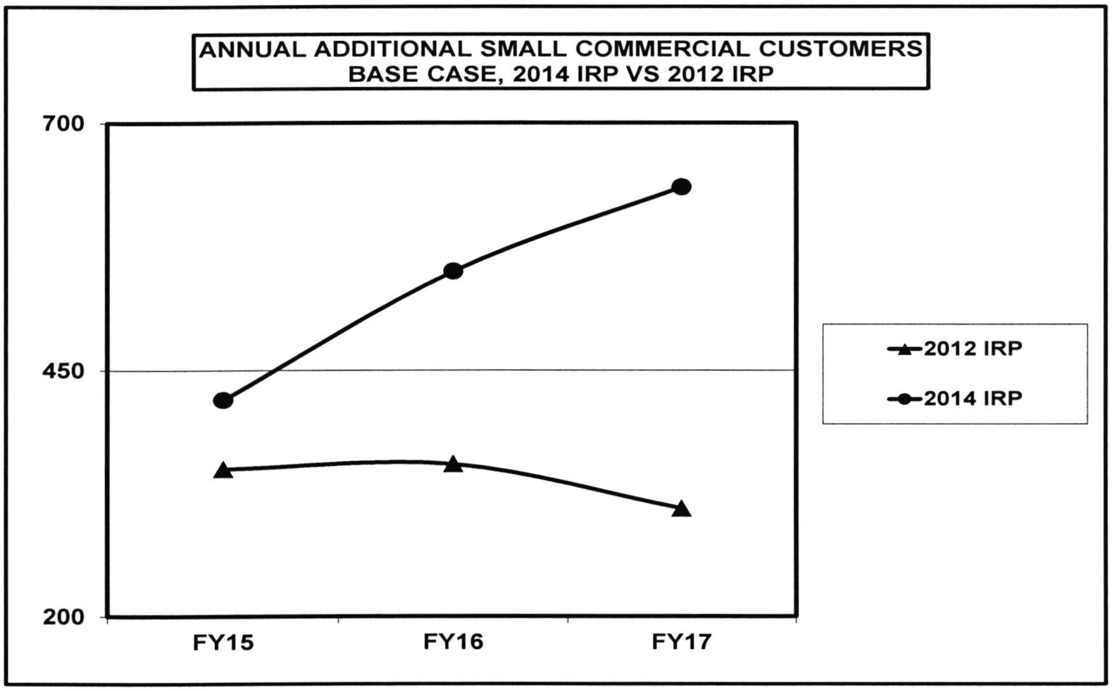
Small commercial customer growth is forecast as a certain proportion of new construction customer additions. The logic being that as household growth drives the major proportion of IGC's residential customer growth; household growth therefore drives small commercial customer growth. New households require additional new businesses to serve them. Based on the most recent three-year sales data, this ratio of small commercial customer growth to residential growth for the West, Central, and East was 6.35%, 9.22%, and 10.47%, respectively. Therefore, regional ratios of 6% for the West, and 9% for Central, and 10% for the East are used in the Base, High, and Low Scenarios.

The following graphs show the annual additional, as well as the annual total small commercial customers for the period 2015 – 2019:






The following graph shows the difference in base case commercial customer growth between the '12 and '14 IRP forecast years common to both studies:



# HEATING DEGREE DAYS AND DESIGN WEATHER

Intermountain's demand forecast captures the influence weather has on system loads by utilizing Heating Degree Days (HDD's). HDD's are a measure of the coldness of the weather based on the extent to which the daily mean temperature falls below a reference temperature base. HDD values are inversely related to temperature meaning that as temperatures decline, HDD's increase. The standard HDD base, and the one Intermountain utilizes in its IRP, is 65°F (also called HDD65). As an example, if one assumes a day where the mean outdoor temperature is 30°F, the resulting HDD65 would be 35 (i.e. 65°F base minus the 30°F mean temperature = 35 Heating Degree Days). Two distinct groups of heating degree days are used in the development of the IRP: Normal Degree Days and Design Degree Days.

Since Intermountain's service territory is composed of a diverse geographic area with differing weather patterns and elevations, Intermountain uses weather data from seven NOAA weather stations located throughout the communities in its service territory. This weather data is "weighted" by the customers in each of the geographic weather districts to arrive at weighted weather for the entire company. Several AOIs are also addressed specifically by this IRP. Those segments are assigned unique degree days as discussed in further detail below.

## Normal Degree-Days

A Normal Degree Day is calculated based on historical data, and represents the weather that could reasonably be expected to occur on a given day. The Normal Degree Day that Intermountain utilizes in the IRP is computed based on weather data for the thirty years ended December 2012. The HDD65 for January 1st for each year of the thirty year period is averaged to come up with the average HDD65 for the thirty year period for January 1st. This method is used for each day of the year to arrive a year's worth of Normal Degree Days.

## Design Degree Day

A Design Degree Day is an estimation of the coldest temperatures that can be expected to occur for a given day. Design Degree Days are useful in estimating the highest level of customer demand that may occur, particularly during extreme cold or "peak" weather events. For IRP load forecasting purposes, Intermountain makes use of design weather assumptions.

Intermountain's design year is based on the premise that the coldest weather experienced for any month, season or year could occur again. The basis of a design year was determined by evaluating the weather extremes over the last thirty years of heating degree day data from NOAA. The review revealed Intermountain's coldest twelve consecutive months to be the 1984/1985 heating season (October 1984 through September 1985). That year, with certain modifications discussed below, represents the base year for design weather. These degree days reflect a set of temperature extremes that have actually occurred in Intermountain's service area. These extreme temperatures would result in a maximum customer usage response due to the high correlation between weather and customer usage.

Intermountain also engaged the services of Dr. Russell Qualls, Idaho State Climatologist, to perform a review of the methodology used to calculate design weather, and to provide suggestions to enhance the design weather planning. One crucial area that Dr. Qualls was able to assist Intermountain in was developing a method to calculate a peak day, as well as in designing the days surrounding the peak day.

## Peak Heating Degree Day Calculation

To develop the peak heating degree day, or coldest day of the design year, Dr. Qualls fitted probability distributions to thirty years of daily temperature data from seven weather station locations (Caldwell, Boise, Hailey, Twin Falls, Pocatello, Idaho Falls and Rexburg). From these distributions he calculated monthly and annual minimum daily average temperatures for each weather location, corresponding to different values of exceedance probability. Two probability distributions were fitted, a Normal Distribution, and a Pearson Type III (P3) distribution. Dr. Qualls suggested it is more appropriate for Intermountain to use the P3 distribution as it is more conservative from a risk reduction standpoint.

According to Dr. Qualls, "selecting design temperatures from the values generated by these probability distributions is preferable over using the coldest observed daily average temperatures because exceedance probabilities corresponding to values obtained from the probability distributions are known. This enables IGC to choose a design temperature, from among a range of values, which corresponds to an exceedance probability that IGC considers appropriate for the intended use".

Intermountain used Dr. Qualls' exceedance probability data to review the data associated with both the 50 and 100 year probability events. After careful consideration of the data, Intermountain determined that the company-wide 50 year probability event, which was an 81 degree day, would be appropriate to use for our design weather model. For modeling purposes, this 81 degree day was assumed to occur on January 15$^{th}$.

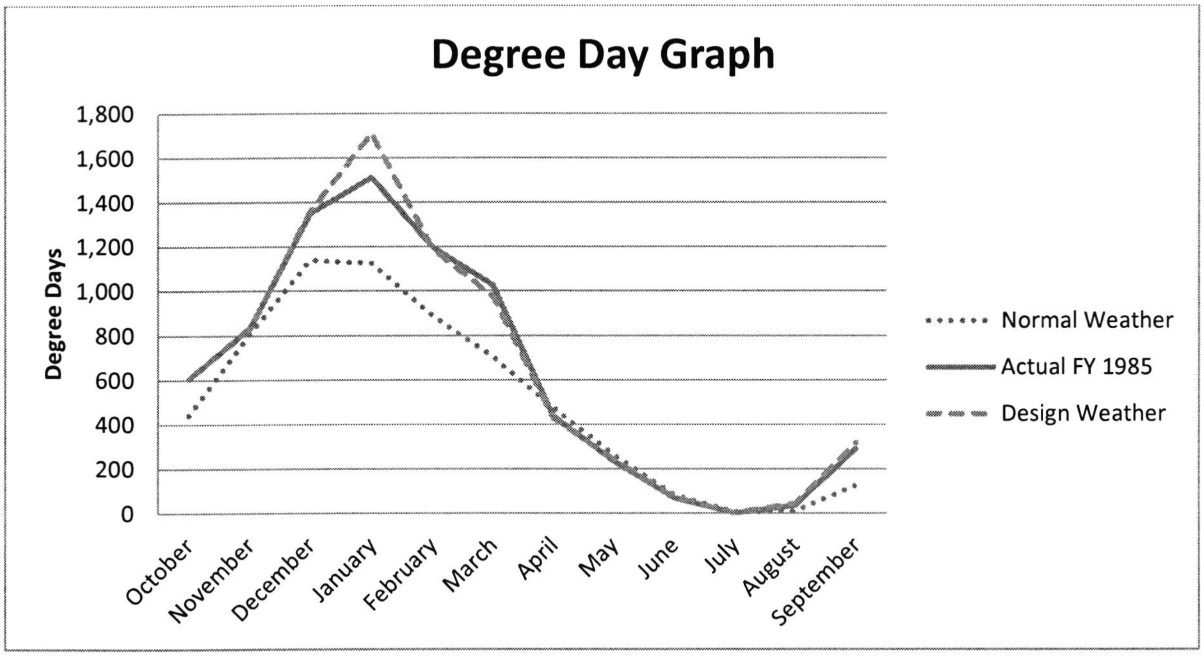
## Base Year Design

To create a design weather year from the base year, a few adjustments were made to the base design year. First, since the coldest month of the last thirty years was December 1985 (1638 HDD's), the weather profile for December 1985 replaced the January 1985 data in the base design year. For planning purposes, the aforementioned peak day event was placed on January 15th.

To model the days surrounding the peak event, Dr. Qualls suggested calculating a 5-day moving average of the temperatures for the thirty year period to select the 5 coldest consecutive days from the period. December 1990 contained this cold data. The coldest day of the peak month (December 1985) was replaced with the 81 degree day peak day. Then, the day prior and three days following the peak day, were replaced with the 4 cold days from the December 1990 cold weather event.

While taking a closer look at the heating degree days used for the Load Demand Curves ("LDC's"), it was noticed that the design weather HDD's in some months were lower than the normal weather HDD's. This occurred generally in the non-winter months, April through July. However, the Total Company and Idaho Falls Lateral design HDD's had this same occurrence in November, although the differences were minimal (1 to 3%). This occurred because, while the 1985 heating year was the coldest on record and therefore used as the base year for the design weather, the shoulder months were, in some cases, warmer than normal. Manipulating the shoulder and summer month design weather to make it colder would add degree days to the already coldest year on record, creating an unnecessary layer of added degree days. Intermountain decided not to adjust the summer and shoulder months of the design year.

After design modifications were complete, the total design HDD curve assumed a bell shaped curve with a peak at mid-January (see Degree Day Graph below). This curve provides a robust projection of the extreme temperatures that can occur in Intermountain's service territory.




The resulting Normal, Base Year, and Design Year degree days by month are outlined in the following table:

**Degree Days By Month**

| Month | Weighted Normal (30 Year Rolling Average) | Actual Heating Year 1985 | Design Weather |
|---|---|---|---|
| October | 441 | 605 | 606 |
| November | 809 | 834 | 833 |
| December | 1,138 | 1,350 | 1,360 |
| January | 1,123 | 1,512 | 1,711 |
| February | 887 | 1,196 | 1,188 |
| March | 703 | 1,026 | 976 |
| April | 473 | 435 | 427 |
| May | 262 | 236 | 241 |
| June | 81 | 69 | 71 |
| July | 5 | 0 | 1 |
| August | 9 | 35 | 43 |
| September | 126 | 288 | 317 |
| Total | **6,056** | **7,586** | **7,774** |

## Area Specific Degree Days

In the 2012 IRP, Intermountain noted unique characteristics of certain Areas of Interest on its distribution system. These are areas Intermountain carefully manages to ensure adequate delivery capabilities either due to a unique geographic location, customer growth, or both.

The temperatures in these areas can be quite different from each other and from the Total Company. For example, the temperatures experienced in Idaho Falls or Sun Valley can be significantly different from those experienced in Boise or Pocatello. Intermountain continues to work on improving its capability to uniquely forecast loads for these distinct areas. A key driver to these area specific load forecasts is area specific heating degree days.

Intermountain has developed Normal and Design Degree Days for each of the Areas of Interest. The methods employed to calculate the Normal and Design Degree Days for each of these areas mirrors the methods used to calculate Total Company Normal and Design Degree Days. Having distinct weather for these areas allows Intermountain to better forecast peak heating loads in areas of the system that have unique weather characteristics, pipeline capacity issues, and population growth patterns.

# USAGE PER CUSTOMER

For the IRP planning process, core market usage per customer is calculated in three segments. First, the critical winter heating season and particularly the peak day usage per customer is calculated using daily usage formulas. Next, the less weather sensitive, non-peak usage per customer is calculated on a monthly basis. Finally, usage per customer is evaluated for the Areas of Interest. Depending on available data customer usage patterns, unique equations are then developed for each AOI.

## Customer Usage During Peak Months

The peak heating season for Intermountain Gas Company is November through February. Because the relationship between weather and usage is so strong during these winter months, it is possible to develop statistically significant daily usage per customer equations. Multiple regression equations were developed for each of the four winter months as outlined in the following section.

### Variable Selection

*Time Series*

The first step in developing the regression equations was to determine the appropriate time period to include in the study. Studies by the American Gas Association show that natural gas usage per customer has decreased by about 1 percent per year for the past 38 years. This means the average U.S. home using natural gas service is using one third less natural gas today than it did three decades ago. Following the national efficiency trend, Intermountain has also noticed a decline in usage per customer in its service territory. Some possible reasons for the decline in usage per customer include the Idaho Residential Energy Code which was adopted by many cities beginning in 1991. This new building standard was designed to improve the energy efficiency of new homes and commercial buildings. About the same time, efficiency standards for furnaces and water heaters were improved. Additionally, programmable thermostats are now installed routinely in new construction, and many people have installed them in older homes as a way to reduce their energy expense (see "The Efficient and Direct Use of Natural Gas", beginning at page 80).

All of these conservation influences began impacting usage in the early 1990's. Since over 65% of Intermountain's customers are new since 1990, the efficiency factors and building codes have had a tremendous influence on our customer base. Rising energy prices have also heightened the customer's interest in conservation. Higher energy prices in recent years have created an economic incentive for people to use natural gas as efficiently as possible, creating downward pressure on Intermountain's usage per customer, and contributing to the structural changes we have seen in the data. Finally, Idaho's economic downturn has impacted usage per customer. Less money in family budgets for energy expenditures has encouraged customers to conserve on natural gas usage where possible, putting additional downward pressure on usage.

To account for these structural shifts in the data, Intermountain used a time series beginning with the winter of 2003/2004 through the winter of 2012/2013 to develop the regression equations.

*Dependent Variable - Daily Usage Per Customer*

The dependent variable, usage per customer, is calculated by dividing the total residential and small commercial market sendout for each day during each of the peak months by total residential and small commercial customers for each day during each of the peak months. Daily customers are developed by evenly spreading the difference between the customers at the beginning of the month and the customers at the end of the month to the days of the month.

*Independent Variables*

The following independent variables were tested as explanatory variables that would help explain changes in usage per customer:

1. Actual sixty-five heating degree-days (65HDD) for each day during the peak months
2. Intermountain Gas natural gas prices
3. Intermountain Gas "Weighted Average Cost of Gas" (WACOG)
4. Consumer Price Index
5. Bank Prime Loan Rate
6. 30-Year Conventional Mortgage Rate
7. Gross Domestic Product
8. Idaho Per Capita Personal Income
9. Number of persons per household (county specific)
10. A weekend binary variable to establish whether or not a relationship exists between usage levels and the weekend.

*Methodology and Results*

A regression equation was developed for each of the peak months. For the months of November, December, and February, the sole statistically significant explanatory variable included in the model to explain changes in daily usage per customer was daily actual 65HDD. The January model includes both 65HDD and a weekend binary variable. (See "Regression Equations," Exhibit 2, Appendix B).

Each of the selected models meets accepted standards for statistical soundness. The models all have high $R^2$ statistics which determine the percent of the variability in usage per customer that is explained by the independent variables. T-statistics for each of the variables indicate they are individually significant ($p>0.05$). The models have all been corrected where necessary to ensure the Durbin-Watson statistic falls within an accepted range, and the F-statistics indicate that the regression models are significant (See "Regression Statistical Output," Exhibit 2, Appendix A).

After the regression equations were developed, design degree-days were used in the models in place of actual 65HDD to calculate the daily usage per customer during the peak months.

## Customer Usage During Non-Peak Months

Modeling usage per customer for the non-peak months begins with a slightly different data set than the peak month usage models. The dramatically different usage patterns of the various classes of customers during the non-peak months as well as a weaker link between weather and usage led Intermountain to develop unique models for RS-1, RS-2 and GS customers. Since Intermountain does not have the capability to collect daily usage by customer class, the Non-Peak month models begin as monthly usage models.

## Variable Selection

*Time Series*

Intermountain has developed a database of historical monthly data going back to 1981. All three customer class models were developed based upon data for this entire data series. However, as outlined in the discussion of "Customer Usage During Peak Months" above, Intermountain has seen structural shifts in the data based upon customer usage patterns and price realities. Since it is difficult to construct variables that effectively model these structural shifts in the data, Intermountain also tested models based upon the shorter datasets of 1990 forward, 2001 forward, 2003 forward, and 2006 forward.

Intermountain found that the time series 2003 forward provided the best statistical fit for all three customer classes. This time series accounts for the structural shifts in the data based on building and efficiency factors, as well as the new market environment brought about by the economic downturn.

*Dependent Variable - Monthly Usage Per Customer*

To calculate separate models for each of the Core market customer classes (RS-1, RS-2 and GS), Intermountain used monthly usage per customer data. The total usage data for the month was divided by customers for that same month to arrive at usage per customer for a given month.

*Independent Variables*

The following independent variables were tested for their statistical validity in explaining changes in usage per customer:

1. Actual sixty-five heating degree-days (65HDD) weighted by customers
2. Intermountain Gas natural gas prices
3. Summer/winter seasonal natural gas prices
4. 2 and 3-year moving average natural gas price
5. Lagged Prices
6. Percent price change year over year
7. Consumer Price Index
8. Bank Prime Loan Rate
9. 30-Year Conventional Mortgage Rate
10. Gross Domestic Product
11. Idaho Per Capita Personal Income
12. Idaho Housing Starts
13. Usage Trends (both annual and winter only)

*Methodology and Results*

A regression equation was developed for each of the three Core market customer classes. The models are all similar in structure in that the 65HDD variable and a winter only trend variable were significant in each case (see "Regression Equations," Exhibit 2, Appendix B).

Each of the selected models meets accepted standards for statistical soundness. The models all have high $R^2$ statistics which determine the percent of the variability in usage per customer explained by the independent variables. T-statistics for each of the variables indicate they are individually significant ($p>0.05$). The models have all been corrected where necessary to ensure the Durbin-Watson statistic falls within an accepted range, and the F-statistics indicate that the regression models are significant (see "Regression Statistical Output," Exhibit 2, Appendix A).

Since the models calculate monthly usage, the constant and trend variables were divided evenly by the days of the month to arrive at a daily factor. Then, the heating degree day coefficient was multiplied by design heating degree days for each day of the month. These components were added together to arrive at daily usage for each day of the month.

## Total Daily Usage

For both peak and non-peak periods, the total usage for each day was calculated by multiplying the usage per customer in both the peak and non-peak periods by the appropriate customers for that day (see Demand Forecast Overview, page 13). Total daily usage varied depending upon the customer growth assumption that was used (i.e. low growth, baseline, or high growth).

## Usage Per Customer By Geographic Area

In a service territory as geographically and economically diverse as Intermountain Gas Company's, we recognize that there could be significant differences in the way customers use natural gas based upon their location on Intermountain's system. Particularly in areas that may require capital improvements to keep pace with demand growth, Intermountain used several methods to analyze whether there was a difference in usage patterns versus the Total Company usage per customer. The AOI's that

Intermountain studied for possible usage per customer refinements included; Canyon County, Central Ada County, State Street lateral, Sun Valley lateral, and Idaho Falls lateral.

CANYON COUNTY

The location of the Canyon County lateral AOI made it impossible to segregate a daily usage per customer for that area. However, Canyon County AOI is located in the most populous region of the service territory. This means the total company data is already weighted more heavily toward representing Treasure Valley usage patterns. Thus, Intermountain determined the total company equations accurately reflected the usage per customer patterns for this AOI.

As the "Heating Degree Days and Design Weather" section outlines, Intermountain has developed Normal and Design Degree Days for the Canyon County AOI. The total company usage per customer equations were applied to these area specific degree days to provide a unique usage forecast that will more accurately predict the loads Canyon County AOI.

CENTRAL ADA COUNTY AND STATE STREET LATERAL

System flow dynamics for both Central Ada County and State Street Lateral AOIs make it impractical to segregate a known, metered daily usage for either area. During review for this IRP planning year it was also noted that both AOIs contain within their boundaries numerous residential and/or commercial customers that have larger than normal consumption, resulting in a usage per customer situation that is higher than the total company average.

Due to this unique situation a separate methodology was used in calculating usage per customer by utilizing a software module to link between Intermountain's customer billing data and the existing pipeline distribution modeling software, SynerGEE Gas. The software module, Customer Management Module (CMM), reviews historical billing information from individual customer meters, compares the billed gas usages to corresponding weather data in the same location and creates a custom usage regression analysis per customer bill. Each customer bill is then linked to a geographic coordinate related to the physical location of the customer, which is then used to assign each regression line to the appropriate pipeline within a SynerGEE model.

Once the CMM analysis is complete, the AOI boundaries are defined within SynerGEE, and then the regression data specific to each AOI is used in conjunction with Intermountain's Normal and Design Degree Days to forecast area specific loading.

SUN VALLEY LATERAL

**Variable Selection**

*Time Series*

In the fall of 2002, Intermountain installed an additional meter on the Sun Valley Lateral to measure natural gas throughput in addition to the existing pressure measurement. Because of an equipment malfunction, the data was lost for the 2003/2004 winter. In reviewing the data, it also became apparent that the data for the 2005/2006 winter was quite low in comparison with other data we had for the area for that time period. The decision was made to remove that year of data from the dataset.

Since Intermountain had these difficulties with the data collecting meters, telemetry equipment was installed that sends the data directly to Intermountain. The data is stored in a database that is regularly backed up, so no additional problems with data loss have occurred. Thus, the final dataset represents ten years of data.

*Dependent Variable – Daily Usage per Customer*

The dependent variable, daily usage per customer, was calculated by taking the total throughput from the Sun Valley lateral meter and subtracting out the industrial load. The resulting core market throughput was then divided by residential and small commercial customers for each day. Daily customers were developed by evenly spreading the difference between the customers at the beginning of the month and the customers at the end of the month to the days of the month.

*Independent Variable*

The following independent variables were tested as explanatory variables that would help explain changes in usage per customer:

1. Actual sixty-five heating degree-days (65HDD) for each day during the peak months
2. Intermountain Gas natural gas prices
3. Intermountain Gas WACOG
4. Consumer Price Index
5. Bank Prime Loan Rate
6. 30-Year Conventional Mortgage Rate
7. Gross Domestic Product
8. Idaho Per Capita Personal Income
9. Number of persons per household (county specific)
10. A weekend binary variable to establish whether or not a relationship exists between usage levels and the weekend.
11. Daily snowfall totals
12. Daily snow depth

*Methodology and Results*

A peak day regression equation was tested for the Sun Valley lateral that included data for the traditional peak month of January for the entire Sun Valley lateral time series outlined above. Daily actual HDD65 and daily snowfall totals were both significant in explaining changes in usage per customer.

Although Intermountain now has an interruptible tariff for snow melt equipment in the Sun Valley area, daily snowfall remains a valid explanatory variable, because existing snow melt equipment was grandfathered on its existing rate schedule at the time the interruptible tariff was adopted. As growth makes existing snow melt a smaller portion of the firm load requirement, Intermountain will monitor the data to see if snowfall continues to make sense as an explanatory variable.

As discussed in the "Heating Degree Days and Design Weather" section, Intermountain calculated lateral specific design degree days which were applied to the Sun Valley lateral regression formula. To calculate peak snowfall, Intermountain looked back over the actual snowfall data from 1990 through 2011 and identified 22 inches as the maximum daily snowfall total. That actual peak amount was applied to the regression formula. The usage per customer resulting from the regression formula was multiplied by Sun Valley lateral customers to arrive at total usage for the lateral.

## IDAHO FALLS LATERAL

### Variable Selection

*Time Series*

During the fall of 2004, Intermountain installed an additional meter on the Idaho Falls Lateral to measure natural gas throughput in addition to the existing pressure measurement. Because of an equipment malfunction, data was lost for the 2005/2006 winter. Since that time, telemetry equipment has also been installed on this meter. The data is sent directly to an Intermountain database and regularly backed up to prevent data loss from occurring in the future. With the loss of the 2005/2006 data, the final dataset represents nine years of data.

*Dependent Variable – Daily Usage per Customer*

The dependent variable, daily usage per customer, was calculated by taking the total throughput from the Idaho Falls lateral meter and subtracting out the industrial load. The resulting core market throughput was then divided by residential and small commercial customers for each day. Daily customers were developed by evenly spreading the difference between the customers at the beginning of the month and the customers at the end of the month to the days of the month.

*Independent Variable*

The following independent variables were tested as explanatory variables that would help explain changes in usage per customer:

1. Actual sixty-five heating degree-days (65HDD) for each day during the peak months
2. Intermountain Gas natural gas prices
3. Intermountain Gas WACOG
4. Consumer Price Index
5. Bank Prime Loan Rate
6. 30-Year Conventional Mortgage Rate
7. Gross Domestic Product
8. Idaho Per Capita Personal Income
9. Number of persons per household (county specific)
10. A weekend binary variable to establish whether or not a relationship exists between usage levels and the weekend.

*Methodology and Results*

A peak day regression equation was tested for the Idaho Falls lateral that included data for the months of November through February for the entire Idaho Falls lateral time series outlined above. Daily actual HDD65 were significant in explaining changes in usage per customer. The overall statistics for this model were not strong, however, and the resulting equation did a poor job of forecasting usage based on actual conditions.

Intermountain's commitment to providing safe, reliable service on a peak day required the use of an alternate method to forecast peak day load. Intermountain next looked at an average usage per customer per degree day. This method forecast usage on a peak day on the Idaho Falls lateral that was roughly the same as the forecast generated by the Total Company regression model applied to unique Idaho Falls lateral degree days. Therefore, Intermountain used the Total Company equation with lateral specific degree days to forecast peak day loads on the Idaho Falls lateral.

# LARGE VOLUME CUSTOMER FORECAST

## Introduction

On average, the large volume customer group accounts for about 45% of Intermountain's annual throughput. Approximately 98% of the large volume throughput is provided through distribution system-only transportation tariffs where the customer delivers its own natural gas supplies to Intermountain's Citygate stations for ultimate redelivery by Intermountain to the customer's facility. Because these transport volumes are such a material part of Intermountain's overall throughput, the method of forecasting is an important part of the IRP. However, since these customers are far less weather sensitive than the core market customers, the company has developed an alternate method of sales forecasting based on historical usage, economic trends and input from these large volume customers.

## Forecasting

Intermountain sent a survey to each of its large volume customers in January 2014. The purpose of the survey was to obtain projections from management, engineers, and marketing personnel for each customer relative to their projected natural gas usage through 2019. The customer's projections incorporate information related to plant expansion, equipment modification or replacement, or anticipated changes in product demand.

The survey form was sent to the management of each of Intermountain's large volume contract customers and included a cover letter explaining the intent of the requested information with the assurance that all responses would remain confidential (see pages 50- 52). The surveys identified customer specific historical peak day and monthly usage for the two years ending 2012. The information helped provide a quick glance of each customer's recent usage patterns to assist them as they projected changes in their future natural gas requirements. The survey requested information related to projected usage, conservation measures and each customer's alternative fuel capabilities. Finally, each customer was asked if they had any recommendations for additional service options. The analysis of the returned surveys was completed in March 2014.

## Forecast Scenarios

For the IRP, Intermountain prepared three separate and distinct large volume monthly gas consumption forecasts (Base Case, High Growth and Low Growth). The survey results were combined with recent usage patterns and economic trends to develop the five-year Base Case forecast. Other available data, including inquiries from economic development organizations, was utilized to develop the High Growth and Low Growth scenarios. For ease of analysis, the 120 existing and 6 projected new customers were combined into six (6) homogeneous market segments:

- 16 potato processors
- 40 other food processors including sugar, milk, beef, and seed companies
- 3 chemical and fertilizer companies
- 25 light manufacturing companies including electronics, paper, and asphalt companies

- 29 schools, hospitals and other weather sensitive customers
- 13 other companies

**Load Profile**

Intermountain has installed SCADA and telemetry systems at nearly every large volume customer and tracks and records the daily usage. The company also has many years of monthly billing data for each customer. From these two data sources, daily and monthly load profiles can be developed for the customers with usage history. The load profiles are extremely useful as a base for each new forecast.

## Firm Contract Demand (MDFQ)

Intermountain does not provide interstate capacity or gas supply for the vast majority of the large volume customer load but only provides capacity on its distribution system. Therefore the IRP optimization model does not utilize the customers' daily or monthly load profiles to estimate usage but instead models industrial loads based on the customers' maximum daily firm demand or MDFQ. Each firm customer has an MDFQ contractual distribution capacity that each customer has the right to access on any day of the year. The optimization model does not assume interruptible loads in the forecast as the distribution system is not designed to serve this load on a peak day. The MDFQ's are loaded directly into the optimization model reflecting the amount of capacity the company reserves these firm customers. The model also assumes that the MDFQ figures also reflect the amount of Citygate gas supply that each transport customer will provide on every day of the year.

Many of the large volumes customers predict that while their peak day may not increase, their annual and/or off-peak day requirements could grow due in part to their use of extended work schedules into weeks or months not previously utilized or additional shifts. The aggregate peak day requirements by AOI are used to analyze the need for future upgrades to the existing laterals serving each community. The total 2014 Large Volume MDFQ increased 4.7% above the 2013 IRP filing.

**Energy Efficiency**

Through discussions with the customers and the information provided via the surveys, it is apparent that maximizing plant efficiency and optimizing production volumes while using the least amount of energy is a very high priority of the owners, operators, and managers of these large volume plants. Intermountain determined that it could assist these customers with their efficiency efforts by providing monthly, daily and hourly historical and real-time natural gas usage. Based on that need, the company developed a system utilizing SCADA technology combined with remote radio telemetry technology to gather, transmit and store a customer's natural gas usage. It then deployed a website where this usage data can be accessed by plant personnel at their convenience via the internet. This near "real-time" information has helped plant managers to understand energy usage helping then to with their energy conservation and efficiency needs.

Additionally, Intermountain offers general consulting assistance to customers and can upon request, provide leak detection and corrosion control information for the natural gas piping systems within the customers' facilities.

### General Assumptions

All current customers were assumed to remain on their current tariff and all forecast scenarios used the 2014 operating budget as a starting point. Projected new customers with annual usage less than 500,000 therms were assumed to be LV-1 and those with usage over 500,000 therms were assumed to be T-4.

It should be noted that during the preparation of the data provided in the survey, it was discovered that the historical daily SCADA data indicated that quite a few of the large volume customer's peak day usage exceeded their actual contract MDFQ. The variance between these figures were compared and assessed customer-by-customer by AOI with the assistance of the engineering group to determine which of the customers were located in geographic areas that currently have available peak day capacity. Where possible, Intermountain will allow those customers to adjust the contract MDFQ to levels consistent with actual peak day use. Those located in areas that do not have available capacity will be required to invest in new facilities in order to increase their MDFQ. The Base Case MDFQ quantities beginning in 2015 include these adjusted MDFQ assumptions.

### Base Case Scenario Summary

The Base Case was compiled using historical usage and surveys with adjustments made to reflect known changes of existing customers. The annual projected usage for the Base Case increased by 22.2 million therms over the five-year period, amounting to 0.268% growth rate.

**Large Volume Base Case Scenario by Market Segment (Thousands of Therms)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | Compound Rate of Growth |
|---|---|---|---|---|---|---|
| **Potato Processors** | 97,580 | 99,292 | 99,992 | 100,592 | 101,212 | 0.9% |
| **Other Food Processors** | 89,255 | 99,715 | 102,045 | 102,265 | 102,285 | 3.5% |
| **Chemical & Fertilizer** | 30,000 | 30,000 | 30,500 | 30,500 | 30,500 | 0.4% |
| **Manufacturers** | 18,380 | 19,240 | 19,380 | 19,430 | 19,480 | 1.5% |
| **Institutions** | 19,650 | 22,805 | 22,980 | 23,175 | 23,390 | 4.5% |
| **Other** | 25,580 | 25,650 | 25,690 | 25,725 | 25,795 | 0.2% |
| **Total Base Case** | 280,445 | 296,702 | 300,587 | 301,687 | 302,662 | 1.9% |

A. The Potato Processors group is forecast to be relatively flat over the five year period. Demand for potato products is flat, and the supply is good. No new plants are on the drawing boards in the near future. Most of the plants in this group are looking for ways to conserve resources while maximizing production, thus lowering the overall cost of product unit.

B. The Other Food Processors group is also projected to be relatively flat over the period.

C. The three plants in the Chemicals/Fertilizers group will continue at current levels with no projected growth and production increases in the forecast. In their forecasts, the managers of these plants assume imported fertilizers will not, at least in the foreseeable future, affect their operations.

D. The Manufacturing group is expected to grow slightly. Some proposed plant expansions might increase manufacturing further.

E. The Institutional group is projected to grow at 0.55% a year, due mainly to fuel switching to gas at BYU Idaho.

F. The usage in the Other group is projected to be relatively flat over the period.

### High Demand Forecast Summary

The High Demand – or most optimistic – forecast figures incorporate usage data directly from the survey with adjustments. The HIGH case forecast starts out approximately 7.5% above the Base Case numbers. The increase from the 2013 annual usage estimate of 265,033,000 therms is projected to increase 5,765,000 therms, or approximately 2.2% over the five year period. The following table summarizes the changes over this period:

**Large Volume High Growth Scenario by Market Segment (Thousand of Therms)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | Compound Rate of Growth |
|---|---|---|---|---|---|---|
| **Potato Processors** | 98,330 | 100,792 | 103,492 | 104,092 | 104,712 | 1.6% |
| **Other Food Processors** | 89,255 | 99,915 | 102,420 | 102,640 | 104,010 | 3.9% |
| **Chemical & Fertilizer** | 30,000 | 30,000 | 30,500 | 30,500 | 30,500 | 0.4% |
| **Manufacturers** | 18,380 | 19,240 | 29,380 | 39,430 | 39,480 | 7.1% |
| **Institutions** | 19,650 | 22,805 | 23,180 | 23,475 | 23,690 | 4.8% |
| **Other** | 25,580 | 25,650 | 29,690 | 31,725 | 31,795 | 5.6% |
| **Total High Growth** | 281,195 | 298,402 | 318,662 | 331,862 | 334,187 | 4.4% |

A. Potato production is up from the 2012 IRP projections, and the future looks steady for the potato industry. This scenario shows the processors flat, although at record high levels. Natural gas prices should stay steady and low which would keep the plants using gas rather than oil.

B. Other Food Processors are projected to be flat across the reporting period again at record high levels. The addition of Chobani and a projected additional cheese plant in the Burley/Rupert area should make up for any production fall-off by other processors. Those plants dealing with cattle are optimistic for steady increases in output.

C. The Chemical/Fertilizer group is projected to increase in size with the addition of a new plant. The three existing plants, plus the forecast additional facility in this group project steady production and usage at high levels.

D. The Manufacturing group is projected to have a slight increase over the period with the addition of two new manufacturing plants – one in the high tech industry, and one asphalt producer.

E. The Institutional group, which is made up mostly of schools and hospitals, is projected by the survey to grow with increased usage at a few.

F. The Other group is projected to grow slightly, with some increased usage at a greenhouse, and an addition of a new user. Usage will be relatively flat across the reporting period in the high case.

### Low Growth Scenario

The projected usage for this scenario is based upon the assumption that the agricultural economy will be flat with very little growth in sales and production. It is also assumed that natural gas prices will be relatively flat, and remain reasonably competitive. With those assumptions, no downturns are projected. Very little growth is forecast in Potato Processing. The Low Growth Scenario projections start 2% below the Base Case in 2013 with overall usage increasing a projected 1% over the period, as shown below.

| Large Volume Low Growth Scenario by Market Segment (Thousand of Therms) | | | | | | |
|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | Compound Rate of Growth |
| Potato Processors | 97,580 | 98,542 | 98,542 | 98,542 | 98,542 | 0.2% |
| Other Food Processors | 89,255 | 98,765 | 100,895 | 100,915 | 100,935 | 3.1% |
| Chemical & Fertilizer | 30,000 | 30,000 | 30,500 | 30,500 | 30,500 | 0.4% |
| Manufacturers | 17,280 | 17,150 | 17,190 | 17,190 | 17,190 | -0.1% |
| Institutions | 19,650 | 22,805 | 22,980 | 23,175 | 23,390 | 4.5% |
| Other | 24,960 | 25,030 | 22,070 | 16,105 | 16,175 | -10.0% |
| Total Low Growth | 278,725 | 292,292 | 292,177 | 286,427 | 286,732 | 0.7% |

A. The price of natural gas was assumed to be competitive against the delivered price of oil. Potato consumption is assumed to remain at current levels. This group, as a whole, looks at any way possible to conserve energy and make its plants more efficient.

B. The Other Food Processor group is expected to remain steady. Existing facilities will remain flat.

C. The projection for the Chemical/Fertilizer group remains flat with no increase or decrease in usage or production.

D. The Manufacturing group is also projected to increase over the period by 0.7% although starting 1.1% below the base case, assuming that no additional "High Tech" production occurs and no unforeseen state or federal highway projects begin.

E. The growth projection for the Institutional group in the low growth forecast is attributed to the known expansion of universities, schools, and hospitals.

F. Facilities in the Other group are projected to increase mainly due to some increased usage at a greenhouse facility.

# SURVEY COVER LETTER

INTERMOUNTAIN®
GAS COMPANY
*A Subsidiary of MDU Resources Group, Inc.*

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January 10, 2014

Name

Company

Address

Address

Dear

Intermountain Gas Company values you as a customer and we are committed to meeting your expectations by providing reliable energy services to your facility. As the economy continues to rebound we see steady growth in natural gas usage from all sectors of our business. That growth coupled with the recent cold snap again emphasizes the importance of our long-term planning efforts.

An Order from the Idaho Public Utilities Commission requires Intermountain to file an Integrated Resource Plan (IRP) every two years. The IRP is comprehensive, long-term plan that gives the Commission the opportunity to assess our forecast including its inputs, underlying methodologies and conclusions. The process encourages public involvement, documents our forecasting efforts and provides assurance that our Plan will enable us to meet your energy needs in a prudent manner.

We are now beginning our next IRP Plan and I am writing to solicit your assistance. In order for our IRP to be as accurate as possible, it is crucial that we incorporate your projected natural gas requirements for the next several years. I have enclosed a survey form that requests a projection of any change in your facility's annual and peak day natural gas requirements and alternate fuel plans. To assist you, I have included annual and peak day (where available) usage information for the two most recent years.

I recognize completion of this survey may require some "extra" effort but I assure you that we do need your data. It will improve the accuracy of our demand forecast which will help Intermountain continue to provide all customers with reliable year-round service. Please return your completed survey, including any comments or questions you may have, by February 7, 2014. As always, any information you provide will be strictly confidential, will not be shared with any other entity and it will be aggregated with data from other customers in any public filing.

Should you have any questions or if I can be of assistance to you, please call me at (208) 377-6118 or (208) 794-4118 or you can email me at dave.swenson@intgas.com.

I thank you in advance,

David Swenson

Manager, Industrial Services

Intermountain Gas Company

Enclosures

# Intermountain Gas Company – 2014- 2019 Large Volume Customer Survey

| | |
|---|---|
| *Company Name:* | *Rate Class:* |
| *Account #* | *Contract Expiration Date:* |
| *Street Address:* | *Contract Demand (or MDFQ):* |
| *City/State/Zip:* | |

## HISTORICAL INFORMATION

| | Annual Therms | Peak Day Therms | Date of Peak Day |
|---|---|---|---|
| 12 Months Actual Ending December 2013 | | | |
| 12 Months Actual Ending December 2012 | | | |

## REQUESTED INFORMATION – PROJECTED THERMS

| Description | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| Annual Therms | | | | | | |
| Peak Day Therms | | | | | | |

What is the prime reason for the projected change in therm use?

__________________________________________________________

Are the 2014-19 therm use projections above lower than they otherwise might have been due to the use of an alternative energy source? ☐ Yes ☐ No
If yes, how much of your 2013 natural gas usage did alternative energy offset? Annual Therms= ________________ Peak Day Therms________________

What percent of your current peak day energy needs, served by natural gas, can be served by existing alternative fuel? ____________________________

What is your existing alternative source of energy? ☐ None ☐ Coal ☐ Oil ☐ Other (specify)

_______________________________________

If you are contemplating incorporating an alternative energy source, what is your preference? ☐ None ☐ Coal ☐ Oil ☐ Other (specify) ________________

Do you plan to employ energy saving or other conservation measures that will reduce your Therms of natural gas?
☐ Yes ☐ No
If yes, please estimate the reduction natural gas Therms (therms or percent): Annual Therms = ______________ Peak Day Therms = _________________



What is the combined total of the input ratings for all natural gas fired equipment? (circle correct units)
______________ **[btu/hr] [MMBtu/hr] [therms/hr] [mcf/d]**

Do you plan to install additional natural gas fired equipment through 2019? ☐ Yes ☐ No

# TRADITIONAL SUPPLY-SIDE RESOURCES

## Overview

The natural gas marketplace continues to change but Intermountain's commitment to act with integrity to provide secure, reliable and price-competitive firm natural gas delivery to its customers has not. In today's energy environment, Intermountain bears the responsibility to structure and manage a gas supply and delivery portfolio that will effectively, efficiently and with best value meet its customers' year-round energy needs. Intermountain will, through its long-term planning, continue to identify, evaluate and employ best-practice strategies as it builds a portfolio of resources that will provide the value of service that its customers expect.

The Traditional Supply Resource section will outline the energy molecule and related infrastructure resources "upstream" of the distribution system necessary to deliver natural gas to the Company's distribution system. Specifically included in this definition is the natural gas commodity (or the gas molecule), various types of storage facilities and interstate gas pipeline capacity. This section will identify and discuss the supply, storage and capacity resources available to Intermountain and how they may be employed in the Company's portfolio approach to gas delivery management.

## Background

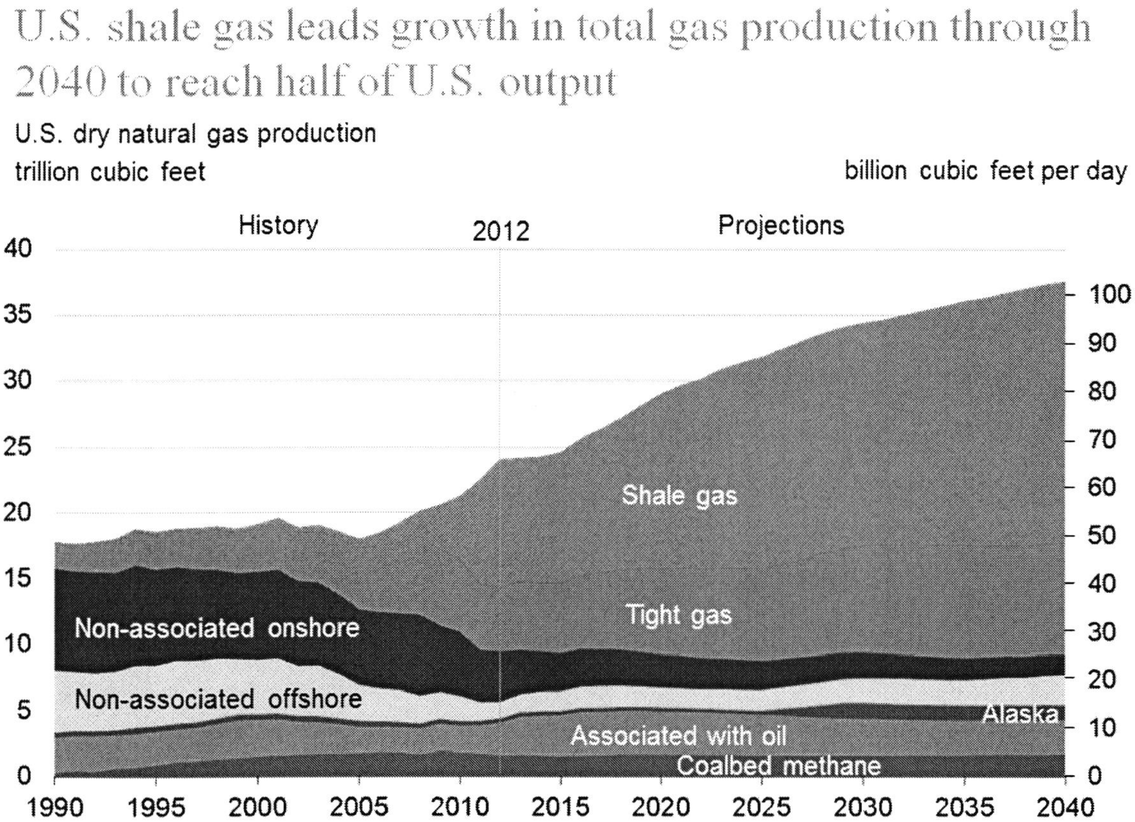
The procurement and distribution of natural gas is in concept a straightforward process. It simply follows the movement of gas from its source through processing, gathering and pipeline systems to end-use facilities where the gas is ultimately ignited and converted into thermal energy. Natural gas is a fossil fuel; a naturally occurring mixture of combustible gases, principally methane, found in porous geologic formations beneath the surface of the earth. It is produced or extracted by drilling into those underground formations or reservoirs and then moving the gas through gathering systems and pipelines to customers in often far away locations.

Intermountain is fortunate to be located in between two prolific gas producing regions in North America. The first, the Western Canadian Sedimentary Basin (WCSB) in Alberta and northeastern British Columba supplies approximately 65% of Intermountain's natural gas. The other region, known as the "Rockies", includes many different producing basins in the states of Wyoming, Colorado and Utah where the remainder of the Company's supplies are sourced. The Company also utilizes storage facilities to store excess natural gas supply during periods of low customer demand and save it for use during periods of higher demand.

Intermountain's access to the gas produced in these basins is wholly dependent upon the availability of pipeline capacity to move gas from those supply basins to Intermountain's distribution system. The Company is also well positioned relating to pipeline capacity as this region has multiple interstate pipeline options providing ample capacity to transport gas to Intermountain' s citygates. A basic discussion of gas supply, storage and interstate capacity resources follow.

## Gas Supply Resource Options

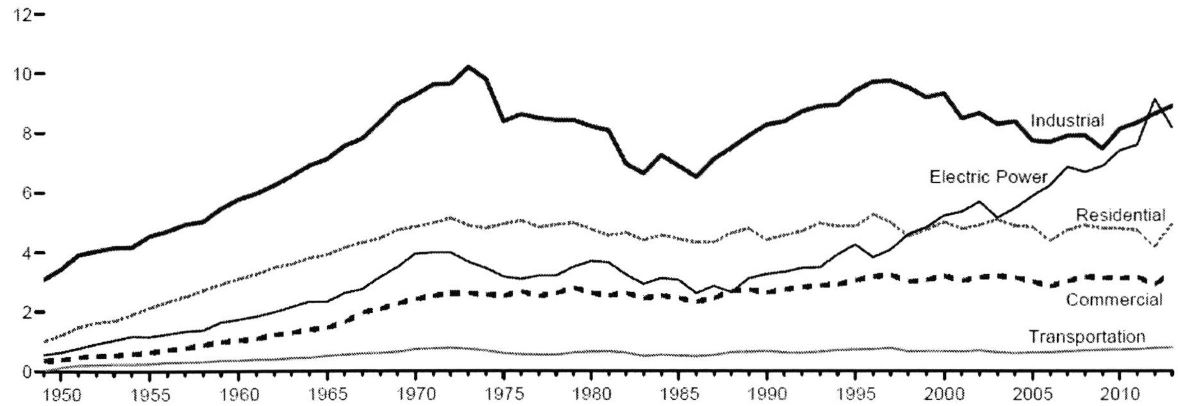
Over the past few years, advances in technology have allowed for the discovery and development of abundant supplies of natural gas within shale plays across the United States and Canada. This shale gas revolution has changed the energy landscape in the United States. Natural gas production levels continue to surpass expectations despite low gas prices and concerns about shale production techniques




*Source: EIA, Annual Energy Outlook 2014 Early Release*

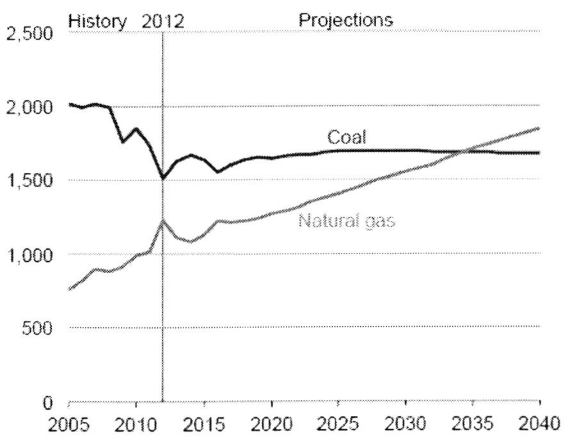
Projected low prices for natural gas have made it a very attractive fuel for natural gas fired electric generation as utilities look for replacement for coal-fired generation. Combine this with the industrial sector's post-recession recovery as they look to take advantage of low natural gas prices, and the result is a significant change in demand loads.

Consumption by Sector, 1949–2013



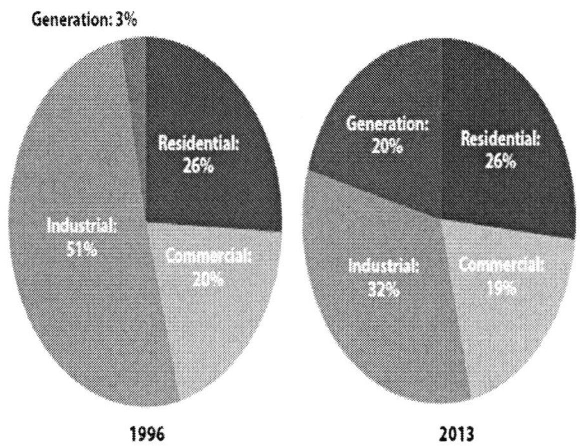

Source EIA

Figure 3. Electricity generation from natural gas and coal, 2005-40 (trillion kilowatthours)




Source: EIA

Figure D4. Shift In Demand Composition




Source: NWGA 2014 Gas Outlook

Improved technologies for finding and producing non-traditional gas supplies have led to huge increases in gas supplies. Exhibit No.4, Chart 2 shows that shale gas production is not only replacing declines in other sources but is projected to increase total annual production levels through 2040.

While natural gas prices continue to exhibit volatility from both a national/global and regional perspectives, the laws of supply and demand clearly govern the availability and pricing of natural gas. Recent history shows that periods of growing demand tends to drive prices up which in turn generally results in consumers seeking to lower consumption. At the same time, producers typically increase investment in activities that will further enhance production. Thus, falling demand coupled with increasing supplies tend to swing prices lower. This in turn leads to falling supplies, increased demand and the cycle begins anew. Finding equilibrium in the market has been challenging for all market participants but at the end of the day, the competitive market clearly works; the challenge is avoiding huge swings that result in either demand destruction or financial distress in the exploration and production business.

Driven by technological breakthroughs in unconventional gas production, major increases in U.S. natural gas reserves and production have led to supply growth significantly outgaining forecasts in recent years. As a result, natural gas producers have sought new and additional sources of demand for the newfound volumes. One proposed end-use is the exportation of U.S. natural gas in the form of liquefied natural gas (LNG). While the United States already exports some quantities of natural gas, mostly via pipeline, current proposals, some of which have already received some level of approval from the federal government, would substantially increase the volume of LNG exports.

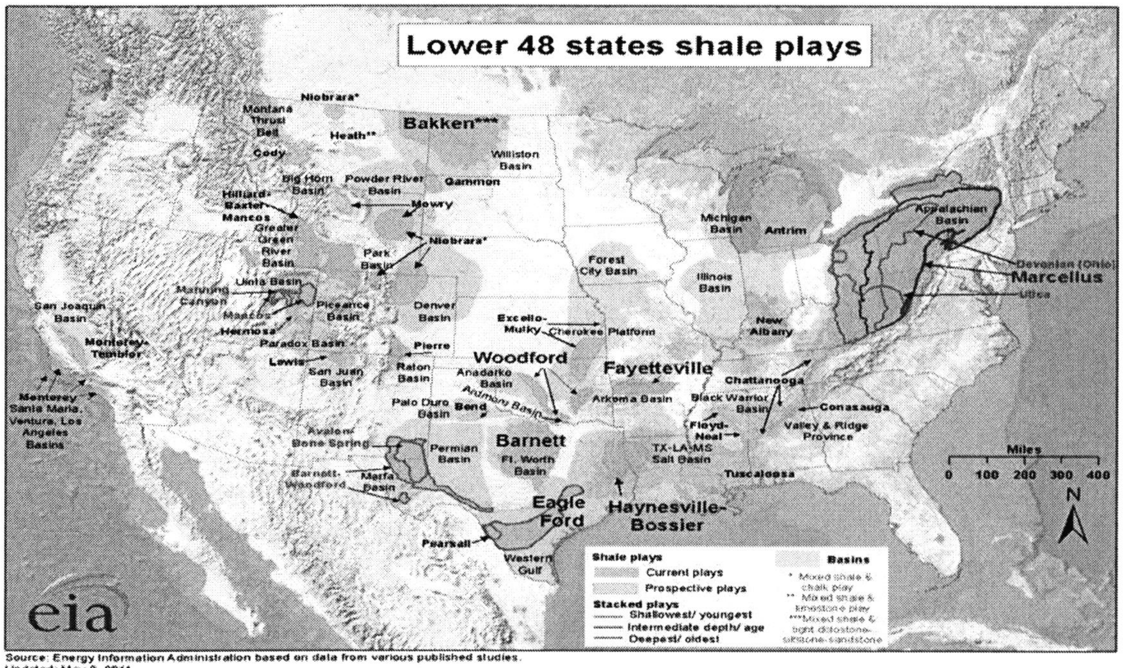
## Shale Gas

Shale gas has changed the face of US energy. Today reserve and production forecasts predict ample and growing gas supplies through 2040 because of shale gas. The fact that shale gas is being produced in the mid-section of the U.S has displaced production from more traditional supply basins in Canada and the Gulf Coast. There have been some perceived environmental issues relating to shale production but most studies indicate that if done properly, shale gas can be produced safely. Customers now enjoy the lowest prices in years due to the increased production of shale gas.

According to EIA, the portion of U.S. energy consumption supplied by domestic production has been increasing since 2005, when it was at its historical low point (69%). Since 2005, production of domestic resources, particularly natural gas and crude oil, have been increasing as a result of shale gas production.

## Supply Regions

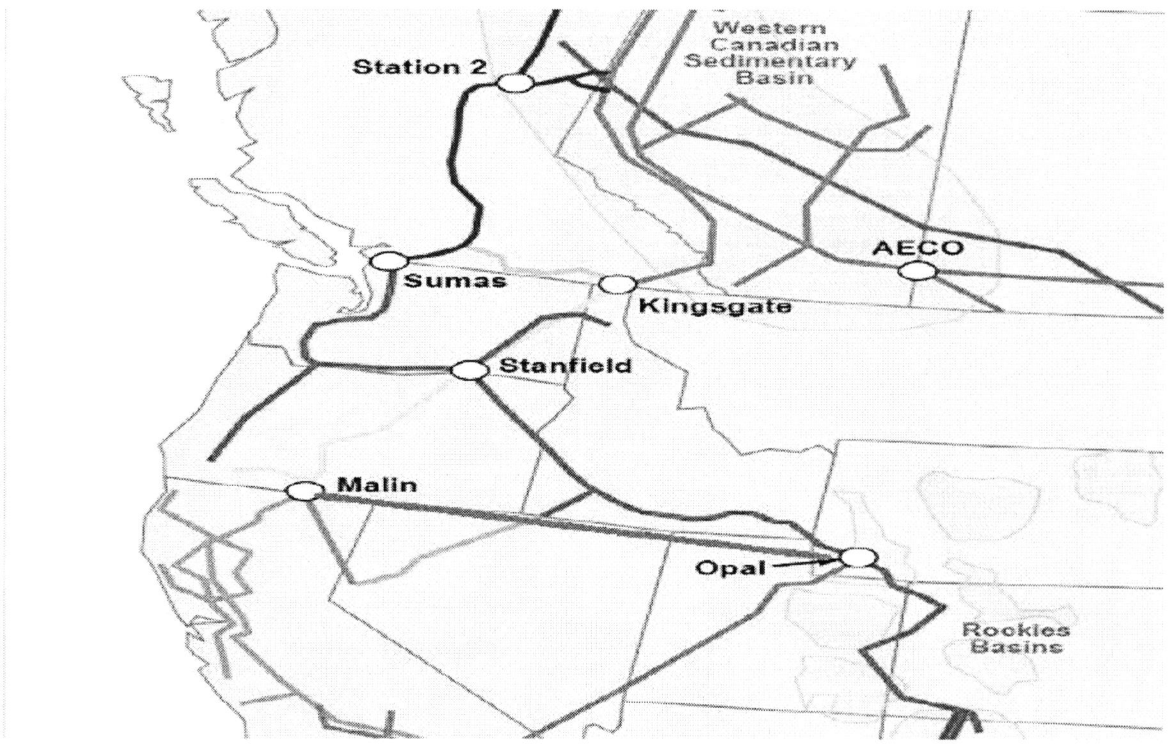
As previously stated, Intermountain's natural gas supplies are obtained primarily from the WCSB and the Rockies. Access to those abundant supplies is completely dependent upon the amount of transportation capacity held on those pipelines so much that a discussion of the Company's purchases of natural gas cannot be fully explored without also addressing pipeline capacity. On average, Intermountain purchases approximately 65% of its gas supplies from the Western Canadian Sedimentary Basin in Alberta and northeast British Columbia and the remainder from the Rockies. Due to pipeline capacity availability Intermountain does not expect to drastically change its historical purchase patterns. The map below identifies the shale plays in the lower 48 states.




Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

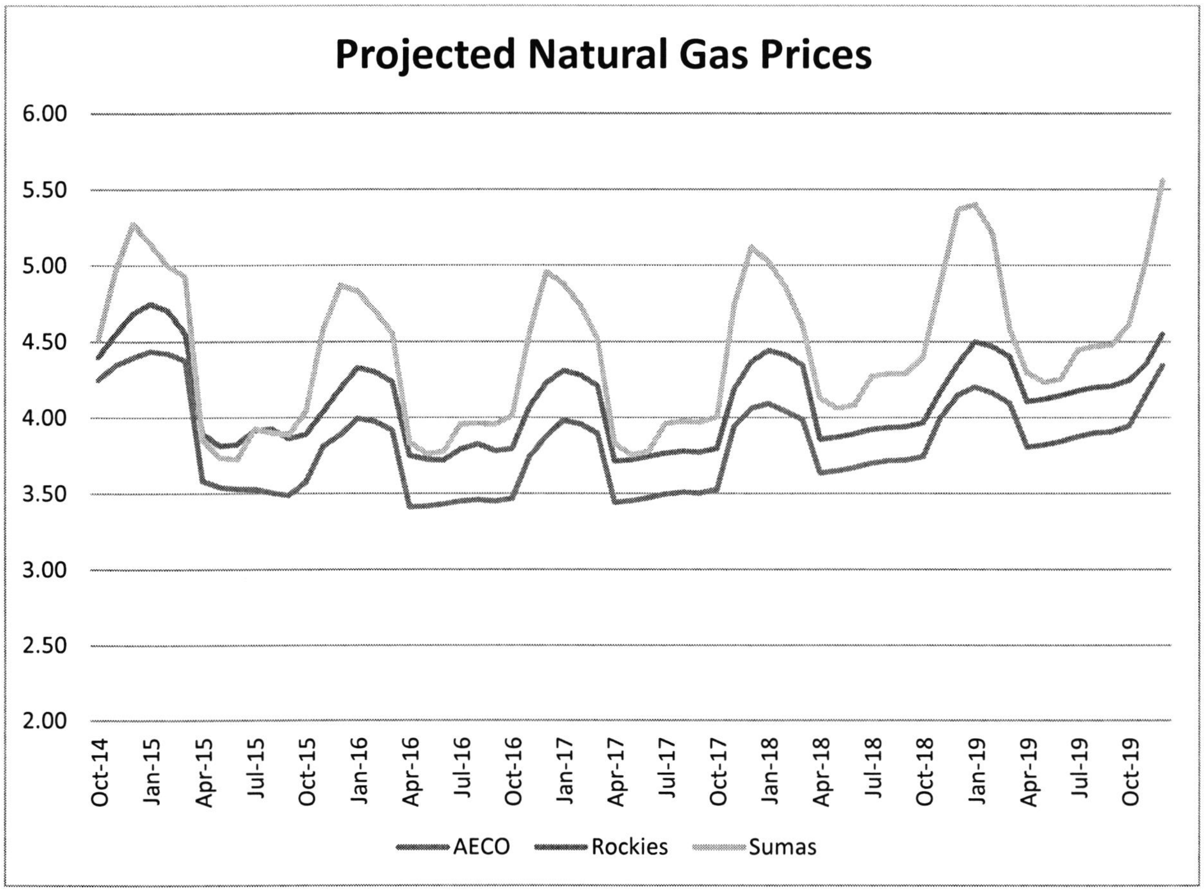
## Alberta

Alberta supplies are delivered to Intermountain via two Canadian pipelines (TransCanada Alberta or "Nova" and "Foothills") and two U.S. pipelines (Gas Transmission Northwest "GTN" and Northwest Pipeline "Northwest") as seen below.



Production in this province has historically been abundant. In fact, at one time Alberta was believed to have the largest natural gas reserves in North America, and annually produced 10 times the Pacific Northwest's yearly consumption. However, we have seen recent production and reserve declines, and some forecasts indicate continuing declines in availability of export gas. The decline is a result of producers not being able to adequately replace the prolific but generally produced reserves in addition to the fact that more Alberta gas is being used in the province to serve growing demand largely in the production of tar sands oil. The expected decline in supplies and significant pipeline capacity used to transport Alberta gas to the Eastern U.S. markets has kept Alberta prices strong in comparison to Rockies supplies. However, Canadian producers are beginning to find and produce its vast regions of unrecovered coal seam and shale formations, thus reversing a trend of declining production.

Alberta gas supplies typically flow to the eastern U.S. and California where price levels are generally higher, meaning that Alberta supplies are historically priced at a premium to Rockies supplies. However, the recent shale gas production increase in the U.S. mid-continent has turned historical price relationships upside down. As more U.S. production reduces the eastward flow of Alberta gas, more of it competes to flow into the western U.S. forcing Alberta producers to seek additional U.S. export markets. Thus Alberta supplies are now very competitive, or even lower than Rockies supply as can be seen in the chart below.




Intermountain will continue to utilize a significant amount of Alberta supplies in its portfolio. The Stanfield interconnect between NWP and GTN offers operational reliability and flexibility over other receipts points both north and south. Where these supplies once amounted to a trickle in the Company's portfolio, today's purchases amount to over 50 percent of the company's annual purchases.

## British Columbia

BC has traditionally been a source of competitively priced and abundant gas supplies for the Pacific Northwest. Gas supplies produced in the province are transported by Spectra Energy to an interconnect with Northwest Pipeline near Sumas, WA. Historically, much of the provincial supply had been somewhat captive to the region due to the lack of alternative pipeline options into Eastern Canada or the Midwest U.S. However, pipeline expansions into Eastern Canada and the Midwest U.S. eliminated that bottleneck. Coupled with declining production in some of the more traditional BC plays, supplies for export into the Northwest have tightened which has resulted in higher prices. So, while there continues to be an adequate supply from BC over and above provincial demand, new discoveries in Northeast BC and the Northwest Territories are critical for future deliverability to Pacific Northwest export markets. Even though these supplies must be transported long distances in Canada and over an international border, there have historically been few political or operational constraints to impede ultimate delivery to Intermountain's Citygates.

## Rockies

Rockies supply has historically been the second largest source of supply for Intermountain because of the ever-growing reserves and production from the region coupled with firm pipeline capacity available to Intermountain. Additionally, Rockies supplies have been readily available, comparatively inexpensive and highly reliable. Historically, pipeline capacity to move Rockies supplies out of the region has been limited which has forced producers to compete with each other to sell their supplies to markets with firm pipeline takeaway capacity. Consequently, Rockies supplies have tended to trade at lower prices than the Canadian or other regional U.S. sources.

Several pipeline expansions out of the Rockies (e.g. Kern River and more recently the completion of Rockies Express pipeline among others) have greatly minimized or eliminated most of the capacity bottlenecks so these supplies now can now more easily move to higher priced markets found in the East or in California. Consequently, even though growth in Rockies reserves and production continues at a rapid pace reflecting increased success in finding tight sand, coal seam and shale gas, the more efficient pipeline system has largely eliminated the price advantage that Pacific Northwest markets have enjoyed. This is not to say that Rockies supplies will be less available to Intermountain but that this region must now compete, more than ever, with markets paying higher prices which could result in an increase in the cost of future Rockies supplies.

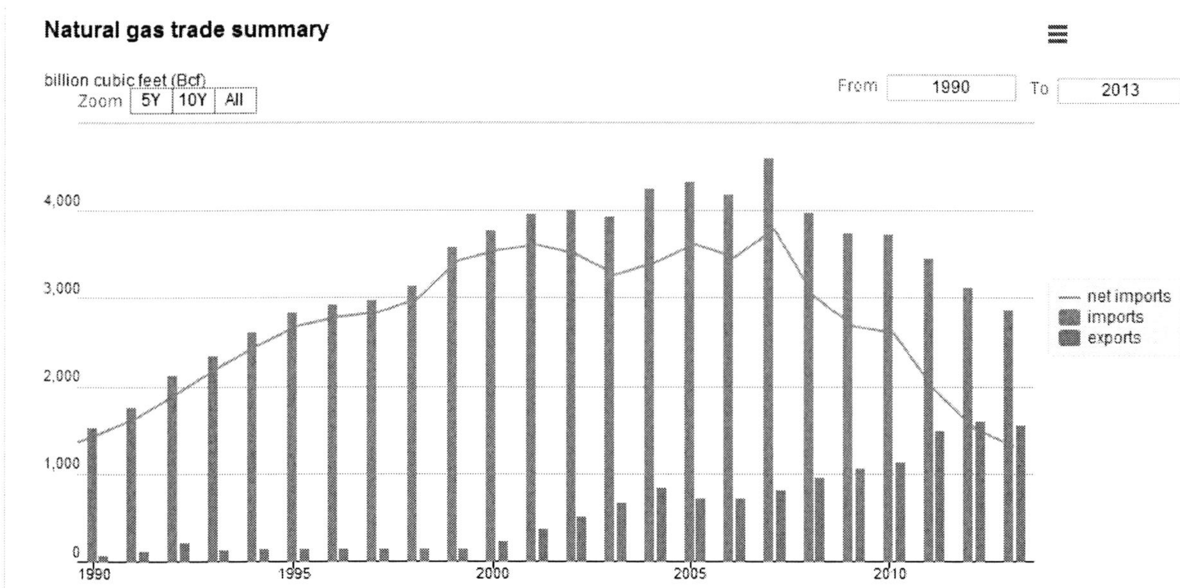
One remaining capacity constraint is found on the NWP system near Kemmerer, Wyoming (just east of the Idaho border) where the amount of Rockies supply flowing northwest into Idaho is limited. Through capacity release opportunities on Northwest, Intermountain has obtained all the capacity it could with receipt points from the Rockies. This has allowed the Company to maximize the amount of Rockies supply which has helped to keep the company's purchased cost of gas low. Today however, there is no excess Rockies capacity available and the cost of physically building new capacity through the Kemmerer constraint point makes that alternative unlikely to happen. The Company therefore must rely on available gas supply at Sumas and Stanfield as incremental supplies are needed in the future. The good news is that Alberta supplies should continue to be plentiful. Long-term the dynamics between Rockies and Alberta supplies should ensure price competitiveness with one another.

## Imported LNG

Another potential supply for the U.S. is Liquefied Natural Gas (LNG) produced in such places as Australia, Trinidad and Tobago and Qatar, which would then be shipped to ports in the U.S. LNG shipments are generally off-loaded into permanent tanks where the liquid is stored until it is vaporized and injected into a pipeline system. While some LNG is currently being imported, the amount as compared to total U.S. demand is very small.

Growth in North American natural gas supplies (see 'Shale Gas' above) has decreased discussion about new LNG import facilities. Because LNG is traded on the global market, where prices are typically tied to oil, U.S. produced LNG is very competitive. Conversation has now turned to several proposed LNG ports which are proposing to *export* LNG to international markets in Asia.

The chart below identifies LNG imports by year going back to 1990. A downward trend going back to 2007 is apparent, and in 2013 LNG imports were at their lowest levels since 1995.




Source EIA

## Types of Supply

There are essentially two main types of supply: firm and interruptible. Firm gas commits the seller to make the contracted amount of gas available each and every day during the term of the contract and commits the buyer to take that gas on each and every day. The only exception would be force majeure events where one or both of the parties cannot control external events that make delivery or receipt impossible. Interruptible or best efforts gas supply typically is bought and sold with the understanding that either party for various reasons, do not have a firm or binding commitment to take or deliver the gas.

Intermountain builds its supply portfolio on a base of firm, long-term gas supply contracts but includes all of the types of gas supplies as described below:

1. Long-term: gas that is contracted for a period of over one year.
2. Short-term: gas that is often contracted for one month at a time.
3. Spot: gas that is for some reason not under a long-term contract; it is generally purchased on a short term basis with a term of anywhere from one day up to periods of one month or even several months.
4. Winter Baseload: gas supply that is purchased for a multi-month period most often during winter or peak load months.
5. Citygate Delivery: natural gas supply that is bundled with interstate capacity and delivered to the utility Citygate meaning that it does not use the Company's existing capacity.

As the natural gas market continues to mature, liquidity at the purchase points Intermountain utilizes has allowed for more flexibility in the structure of the portfolio. The historical heavy reliance on mostly longer-term contracts for the majority of the portfolio has lessened as the Company has found that it can shift more of its supplies to shorter termed spot or index contracts. Doing so provides increased flexibility to balance supplies with seasonal demand and take advantage of price shifts without having excess supply in off-peak periods.

## Pricing

Long-term firm supplies have historically been priced flat to, or at a small premium to, the applicable monthly index priced. As market conditions change over time, Intermountain has found that contracts containing negotiable market sensitive price premiums or discounts allow both buyer and seller to be more comfortable that longer term contracts remain market competitive. The Company also actively manages its various firm receipt points so that to the extent possible, purchases are made at the lowest price possible. Intermountain includes several year-round and winter-only term supply contracts in its portfolio.

Spot gas is typically gas that suppliers, for various reasons, do not contact on a term delivery basis. The term "spot gas" may apply to gas sold under differing terms including firm, interruptible, swing, day gas or best efforts and is usually available at almost any time at varying volumes, prices and contract terms. Spot gas may be bought for one or several days a time, for one month or even for seasonal periods such as the summer injection periods. During peak usage periods, day-to-day spot may be difficult to find, be relatively expensive, unreliable or may be available only on a day-to-day basis. Of course in non-peak months, spot is most often readily found and is often, but not always, inexpensive when compared to term supply.

Intermountain frequently purchases firm spot supplies for a given month and as a rule, targets those suppliers with reputation for reliability. Intermountain is also active in the spot market as it manages its daily position with the various pipelines on which it flows gas supplies. The Company may use interruptible supplies when a failure to delivery would not result in a risk of serving its firm customers. For example, interruptible supply may be used to supplement summer storage injections because a failure would not jeopardize any customers and the injection could be easily be made up on a subsequent day. Of course, in order to purchase such gas supply, the Company would require an attractive price.

The Company does not currently utilize NYMEX based products to "hedge" forward prices but has found many suppliers that will fix future purchase prices. Doing so provides the same price protection without the credit issues that come with financial instruments. A certain level of fixed price contracts allows Intermountain to participate in the competitive market while avoiding much of the price While the Company does not utilize a fully mechanistic approach, its Gas Supply Committee meets frequently to discuss all gas portfolio issues, including fixing prices, in order to provide stable and competitive prices for its customers.

For optimization purposes, Intermountain obtained two five-year price forecasts for the Aeco, Rockies and Sumas pricing points from two multi-national energy companies based on the April 2, 2014 market close. After evaluation, it was determined that although the forecasts were not perfectly identical (as would be expected), the trends and seasonal pricing levels were actually very similar to one another. Therefore, the Company determined that it could reasonably use one of the forecasts for modeling purposes. The selected forecast included a monthly base price projection for each of the three purchase points.

## Storage Resources

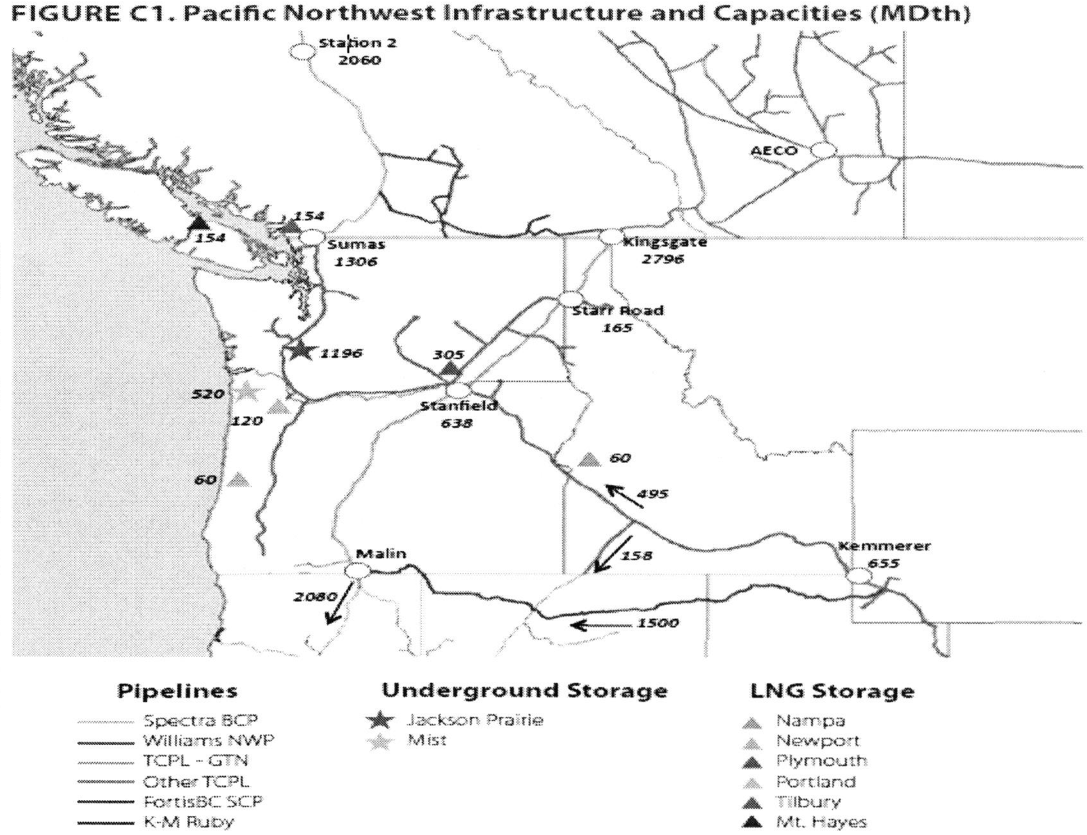
As previously discussed, the production of natural gas and the amount of available pipeline capacity are very linear in nature; changes in temperatures or market demand does not materially affect how much of either is available on a daily basis. As seen in the Load Demand Curve section of this IRP, the steep drop off in core market demand means that attempting to serve peak demands with a level amount of daily gas supplies and maximum pipeline capacity would be enormously expensive as the vast majority of those resources would be utilized, at best, only a few days each year. So the ability to store natural gas during periods of non-peak demand for use during peak periods is a cost efficient way to fill the gap between static levels of supply and capacity vs. the non-linear demand curve.

Intermountain utilizes storage capacity in four different facilities from western Washington to northeastern Utah. Two are operated by Northwest: one is an underground project located near Jackson Prairie, WA ("JP") and the other is a liquefied gas ("LS") facility located near Plymouth, WA (See map below). Intermountain also leases capacity from Questar Pipeline's Clay Basin underground storage field and also operates its own LNG facility located in Nampa, ID.

All four locations allow Intermountain to inject excess gas into storage during off-peak periods and then hold it for withdrawal whenever the need arises. The advantage is three-fold: one, the Company can serve the extreme winter peak while minimizing year-round firm gas supplies; two, storage allows the

Company to minimize the amount of the year-round interstate capacity resource and helps it to use existing capacity more efficiently; and three, storage provides a natural price hedge against the typically higher winter gas prices. Thus storage allows the Company to meet its winter loads more efficiently and in a cost effective manner.

FIGURE C1. Pacific Northwest Infrastructure and Capacities (MDth)




## Liquefied Storage

Liquefied storage facilities make use of a process that super cools and liquefies gaseous methane under pressure until it reaches approximately minus 260°F. Liquefied natural gas ("LNG") occupies only one-six-hundredth the volume compared to its gaseous state and so it is an efficient method for storing peak requirements. LNG is also non-toxic; it is non-corrosive and will only burn when vaporized to a 5-15% concentration with air. Because of the characteristics of liquid, its natural propensity to boil-off and the enormous amount of energy stored, LNG is normally stored in man-made steel tanks.

Liquefying natural gas is, relatively-speaking, a time-consuming process, the compression and storage equipment is costly and liquefaction requires large amounts of added energy. It typically requires as much as one unit of natural gas burned as fuel for every three to four units liquefied. Also, a full liquefaction cycle may take 5 – 6 months to complete. Because of the high cost and length of time involved filling a typical LNG facility, it has typically been "cycled" only once per year and is reserved for peaking purposes. This makes the unit cost somewhat expensive when compared to other options.

Vaporization, or the process of changing the liquid back into the gaseous state, on the other hand, is a very efficient process. Under typical atmospheric and temperature conditions, the natural state of methane is gaseous and lighter than air as opposed to the dense state in its liquid form. Consequently, vaporization requires little energy and can happen very quickly. Vaporization of LNG is usually accomplished by utilizing pressure differentials by opening and closing of valves in concert with some hot-water bath units. The high pressure LNG is vaporized as it is warmed and is then allowed to push itself into the lower pressure distribution system. Potential LNG daily withdrawal rates are normally large and, as opposed to the long liquefaction cycle, a typical full withdrawal cycle may last less than 10 days or less at full rate. Because of the cost and cycle characteristics, LNG withdrawals are typically reserved for "needle" peaking during very cold weather events or for system integrity events.

Neither of the two LNG facilities utilized by Intermountain requires the use of year-round transportation capacity for delivery withdrawals to Intermountain's customers. The Plymouth facility is bundled with redelivery capacity for delivery to Intermountain and the Nampa LNG tank withdrawals go directly into the Company's distribution system. The IRP assumes liquid storage will serve as a needle peak supply. Recent new market developments provide new potential opportunities to utilize LNG storage on a year-round basis without jeopardizing peak vaporization. Intermountain is continually assessing these opportunities to more fully utilize the asset and provide more cost recovery for its utility customers.

## Underground Storage

This type of facility is typically found in naturally occurring underground reservoirs or aquifers (e.g. depleted gas formations, salt domes, etc.) or sometimes in man-made caverns or mine shafts. These facilities typically require less hardware compared to LNG projects and are usually less expensive to build and operate than liquefaction storage facilities. In addition, commodity costs of injections and withdrawals are usually minimal by comparison. The lower costs allow for the more frequent cycling of inventory and in fact, many such projects are utilized to arbitrage variations in market prices.

Another material difference is the maximum level of injection and withdrawal. Because underground storage involves far less compression as compared to LNG, maximum daily injection levels are much higher so a typical underground injection season is much shorter, maybe only 3-4 months. But the lower pressures also mean that maximum withdrawals are typically much less than liquefied storage at maximum withdrawal. So it could take 35 days or more to completely empty an underground facility. The longer withdrawal period and minimal commodity costs make underground storage an ideal tool for winter baseload (i.e. filling the winter "hump" in the LDC) or daily load balancing and therefore Intermountain normally uses underground storage before liquid storage is withdrawn.

Intermountain contracts with two pipelines for underground storage: Questar Pipeline's ("Questar") for capacity at its Clay Basin facility in Northeastern Utah and Northwest for capacity at its Jackson Prairie facility. Clay Basin provides the Company with the largest amount of seasonal storage and daily withdrawal. However, since Clay Basin is not bundled with redelivery capacity, Intermountain must use its year-round capacity when these volumes are withdrawn. For this reason, the Company normally "baseloads" Clay Basin withdrawals during the November-March winter period.

Just like Northwest's Plymouth LS facility, Northwest's JP storage is bundled with redelivery capacity so Intermountain typically layers JP withdrawals between Clay Basin and its LNG withdrawals. The IRP uses

Clay Basin as a winter baseload supply and JP is used as the first "layer" of peak supply. The Table below outlines the Company's storage resources for this IRP.

**Table 1**

**Storage Statistics**

| | Seasonal | Daily Withdrawal | | Daily Injection | | Redelivery |
|---|---|---|---|---|---|---|
| Facility | Capacity | Max Vol | % of 2013 Peak | Max Vol [1] | # of Days | Capacity |
| **Nampa** | 580,000 | 60,000 | 12% | 3,500 | 166 | ***None*** |
| **Plymouth** | 1,096,235 | 113,200 | 23% | 5,660 | 200 | **TF-2** |
| **Subtotal Liquid** | 1,676,235 | 173,200 | 35% | 9,160 | | |
| **Jackson Prairie** | 1,099,099 | 30,337 | 6% | 15,000 | 73 | **TF-2** |
| **Clay Basin** | 8,413,500 | 70,109 | 14% | 53,933 | 156 | **TF-1** |
| **Subtotal Undgrnd** | 9,512,599 | 100,446 | 20% | 68,930 | | |
| **Grand Total** | 11,888,834 | 273,646 | 55% | 78,093 | - | - |

[1] These figures are based on tariff or contact language; however real-world experience suggests that Plymouth and Clay Basin average daily injections are much higher therefore the number of injection days are less.

All four storage facilities require the use of Intermountain's every-day, year-round capacity for injection or liquefaction. Because injections usually occur during the summer months, use of year-round capacity for injections actually helps the Company to make more efficient use of its every-day transport capacity and term gas supplies during those off-peak months when the Core Market loads are lower.

## Storage Summary

The company generally utilizes its diverse storage assets to offset winter load requirements, provide peak load protection and, to a lesser extent, for system balancing. Intermountain believes that the geographic and operational diversity of the four facilities utilized offers the company and its customers a level of efficiency, economics and security not otherwise achievable. Geographic diversity provides security should pipeline capacity become constrained in one particular area. The lower commodity costs and flexibility of underground storage allows the company flexibility to determine its best use from other supply alternatives such as winter baseload or peak protection gas, price arbitrage or system balancing.

## Interstate Pipeline Transportation Capacity

As earlier discussed, Intermountain is dependent upon pipeline capacity to move natural gas from the areas where it is produced, to end-use customers who consume the gas. In general, firm transportation capacity provides a mechanism whereby a pipeline will reserve the right, on behalf of a designated and approved shipper, to receive a specified amount of natural gas supplies delivered by that shipper, at designated points on its pipeline system and subsequently redeliver that volume to particular delivery point(s) as designated by the shipper.

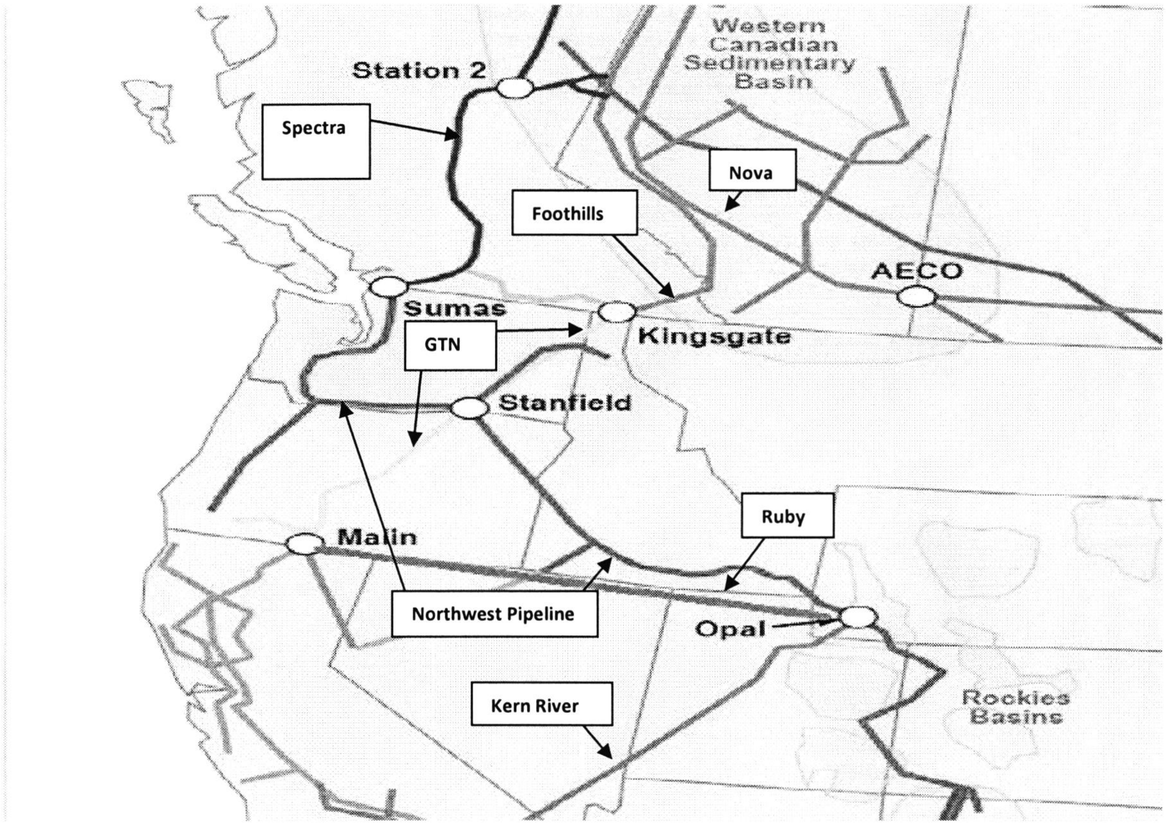
Intermountain holds firm capacity on four different pipeline systems including Williams Northwest Pipeline. Northwest is the only interstate pipeline which interconnects to Intermountain's distribution system, meaning that Intermountain physically receives all gas supply to its distribution system via "Citygate" taps with Northwest. Table 1 below summarizes the Company's year-round capacity on Northwest (TF-1) and its storage specific redelivery capacity. Between the amount of capacity Intermountain holds on the "Upstream" pipelines (GTN, Foothills, and Nova) and firm-purchase contracts at Stanfield, it controls enough capacity to deliver a volume of gas commensurate with the Company's Stanfield takeaway capacity on Northwest.

**Table 2**

**Northwest Pipeline Transport Capacity**

| Delivery Quantity | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| **TF-1 Capacity-** | | | | | |
| **Sumas** | 17,291 | 17,291 | 17,291 | 17,291 | 17,291 |
| **Stanfield** | 158,670 | 158,670 | 158,670 | 158,670 | 158,670 |
| **Rockies** | 84,328 | 84,328 | 84,328 | 84,328 | 84,328 |
| **Citygate** | 18,056 | 18,056 | 18,056 | 18,056 | 18,056 |
| **Total TF-1** | 278,345 | 278,345 | 278,345 | 278,345 | 278,345 |
| **Storage (TF-2)** | 143,537 | 143,537 | 143,537 | 143,537 | 143,537 |
| **Max. Citygate Delivery** | 421,882 | 421,882 | 421,882 | 421,882 | 421,882 |

Northwest Pipeline's facilities essentially run from the Four Corners area north to western Wyoming, across Southern Idaho to Western Washington. The pipeline then continues up the I-5 corridor where it interconnects with Spectra Energy, a Canadian pipeline in British Columbia, near Sumas, Washington where it receives natural gas produced in northeast British Columbia. Gas supplies produced in the province of Alberta Northwest are delivered to Northwest via Gas Transmission Northwest (GTN) near Stanfield, Oregon. Northwest also connects with other U.S. pipelines and gathering systems in several western U.S. states ("Rockies") where it receives gas produced in basins located in Wyoming, Utah, Colorado and New Mexico. The major pipelines in the Pacific Northwest, several of which Northwest Pipeline interconnect with can be seen below.




Because natural gas must flow along pipelines with finite flow capabilities, demand frequently cannot be met from a market's preferred basin. Competition among markets for these preferred gas supplies can cause capacity bottlenecks and these bottlenecks often result in pricing variations between basins supplying the same market area. In the short to medium term, producers in constrained basins invariably must either discount or in some fashion differentiate their product in order to compete with other also constrained supplies. In the longer run however, disproportionate regional pricing encourages capacity enhancements on the interstate pipeline grid, from producing areas with excess supply, to markets with constrained delivery capacity. Such added capacity nearly always results in a more integrated, efficient delivery system that tends to eliminate or at least minimize such price variances.

Consequently, new pipeline capacity - or expansion of existing infrastructure – in western North America has increased take-away capacity out of the WCSB and the Rockies, providing producers with access to higher priced markets in the Midwest and in California. Therefore, less-expensive gas supplies once captive to the Northwest region of the continent now have greater access to the national market resulting in less favorable price differentials for the Pacific Northwest market. Today, wholesale prices at the major trading points supplying the Pacific Northwest region are trending towards equilibrium indicative of a fungible commodity. At the same time, new shale gas production in the mid-continent is beginning to displace traditionally higher-priced supplies from the Gulf coast which, from a national perspective, appears to be causing an overall softening trend in natural gas prices with less regional differentials.

Today Intermountain is in an increasingly mega-regional marketplace where market conditions across the continent - including pipeline capacities - can, and often do, affect regional supply availability and pricing dynamics. While gas supplies are readily available and national prices show a short-term softening trend, Intermountain is increasingly competing with markets that have historically paid higher prices to obtain gas supplies. In the long run, many forecasts predict tightening price differentials across the continent.

## Capacity Release

Capacity release was implemented by FERC to allow markets to more efficiently utilize pipeline capacity. This mechanism allows a shipper with any unused capacity to auction the excess to another shipper offering the highest bid. Thus capacity that would otherwise sit idle can be used by a replacement shipper. The result is a more efficient use of capacity as replacement shippers maximize annualized use of existing capacity. One result is that pipelines are less inclined to build new capacity until the market recognizes that it is really needed and is willing to pay for new infrastructure. But a fuller pipeline can also mean existing shippers find less operational flexibility.

Intermountain has and continues to be active in the capacity release market. Intermountain has obtained significant amounts of capacity on Northwest and GTN via capacity release. The Company frequently releases seasonal and/or daily capacity during periods of reduced demand. In the past, Intermountain utilized a specific type of capacity release called segmentation to move firm receipt capacity from Sumas to Stanfield. Doing so not only provided certain capacity release credits but also provided more supply diversity as reliance on BC supplies was decreased.

Capacity release also resulted in a bundled service called Citygate delivered gas supplies as some marketers were able to use available capacity to sell gas directly to a market's gate stations. Thus a market like Intermountain could contract for supplies only for a specified time period – a peak or winter period for example – that would ensure delivery of additional gas supplies without having to contract more year-round capacity which would not be used during off peak periods.

## New Pipeline Capacity

There are currently several pipeline projects proposed for the Northwest (see Figure 1 below). Two are designed to increase capacity into the I-5 corridor between Sumas and Portland (Blue Bridge/Palomar and Washington Expansion) and another will increase capacity in southern BC (Southern Crossing). The other project (Pacific Connector) will provide a link with existing pipeline systems that converge at Malin, Ore with a proposed Coos Bay export terminal in southern Oregon.

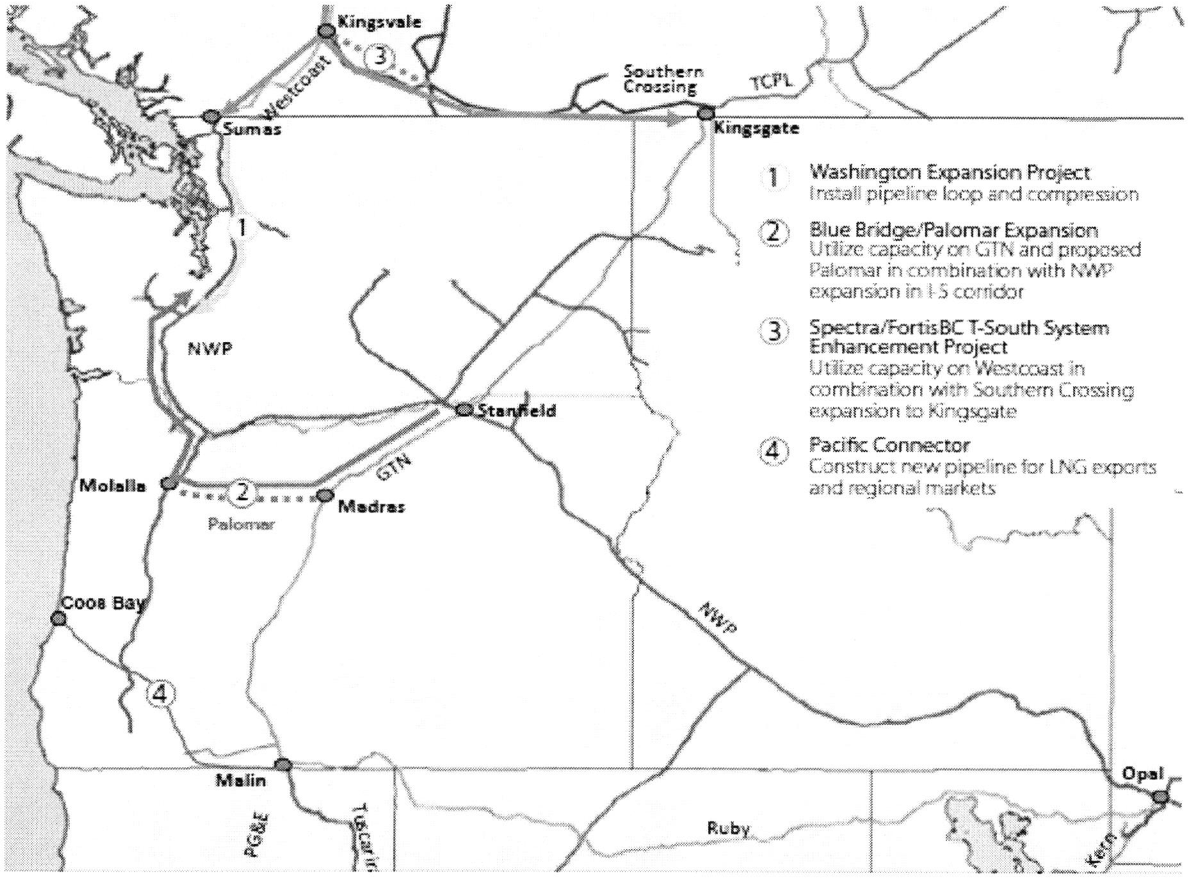



**Figure 1**

None of the these pipeline proposals would directly deliver gas supply into Idaho but it is possible that through displacement (i.e. as more gas moves into the Pacific Northwest, it offsets other gas supplies traditionally flowing into the same area), gas supplies typically flowing to markets on the west coast could be available to the existing markets in Idaho. Alternatively, it could be possible to backhaul supply from the interconnect where Ruby crosses Paiute Pipeline in Nevada into Northwest Pipeline in southern Idaho but the cost of doing so is presently not economic.

## Regulation

All activity regarding transportation of natural gas supplies through any part of the interstate pipeline grid continues to be under the review and regulatory oversight of the Federal Energy Regulatory Commission (FERC). For in-state regulatory matters, the Idaho Public Utilities Commission ("IPUC") provides oversight and oversees all aspects of natural gas service to Intermountain's customers. Under tariffs approved by the IPUC, Intermountain provides sales and transport-only services to over 320,000 customers in southern Idaho.

The vast majority of Intermountain's customers – including all residential and commercial customers - receive a fully-bundled sales service where the Company provides the natural gas and all transportation capacity needed to deliver natural gas directly to the customer's meter. A handful of the Large-volume (also called "Industrial") customers also receive the bundled sales service. However, most of Intermountain's industrial customers receive transport-only service on the distribution system under two different tariffs. Intermountain's T-4 and T-5 customers receive firm distribution-only transport where the customer's gas is received at the Company's applicable Citygates and then transported through the Company's distribution system and redelivered to the customers' facilities. The Company also transports distribution system-only gas under a similar interruptible T-3 tariff.

## Supply Resources Summary

Because of the dynamic environment in which it operates, the Company will continue to evaluate customer demand in order to provide an efficient mix of the above supply resources so as to meet its goal of providing reliable, secure, and economic firm service to its customers. Intermountain actively manages its supply and delivery portfolio and consistently seeks additional resources where needed. The Company actively monitors natural gas pricing and production trends in order to maintain a secure, reliable and price competitive portfolio and seeks innovative techniques to manage its transportation and storage assets in order to provide both economic benefits to the customers and operational efficiencies to its interstate and distribution assets. The IRP process culminates with the optimization model that helps to ensure that the Company's strategies to meet its traditional gas supply goals are based on sound, real-world, economic principles.

# NON-TRADITIONAL SUPPLY RESOURCES

Non-traditional supply resources help supplement the traditional supply-side resources during peak demand conditions. Non-traditional resources include two general types: energy supplies not received from an interstate pipeline supplier, producer or interstate storage operator and various methods used to increase capacity within the Company's distribution system that enhance the ability to flow gas during periods of peak demand. Five (5) non-traditional supply resources and three (3) capacity upgrade options were considered in this IRP and are as follows:

Non-Traditional Supply Resources

1. Diesel/Fuel Oil
2. Coal
3. Wood Chips
4. Propane
5. Satellite/Portable LNG Facilities

Capacity Upgrades

1. Pipeline Loop
2. Pipeline Uprate
3. Compressor Station

## Non-Traditional Resources

While a large volume industrial customers' load profile is relatively flat compared to the Core Market, the industrials are still a significant contributor to overall peak demand. However, some industrials have the ability to use alternate fuel sources to temporarily reduce their reliance on natural gas. By using alternative energy resources such as coal, propane, diesel and wood chips, an industrial customer can lower their natural gas requirement during peak load periods while continuing to receive the energy required for their specific process. Although these alternative resources and related equipment typically have the ability to operate any time during the year, most are ideally suited to run during peak demand from a supply resource perspective. However, only the industrial market has the ability to use any of the aforementioned alternate fuel in large enough volumes to make any material difference in system demand. More specifically, only industrial customers located along the Idaho Falls Lateral (IFL) have the ability to use any of these non-traditional resources to offset firm demand throughout a system. In order to rely on these types of peak supplies Intermountain would need to engage in negotiations with specific customers to ensure availability. The overall expense cost of these kinds of arrangements, if any, is difficult to assess.

The remaining non-traditional resource, Satellite/Portable liquid natural gas (LNG) facility, is technically not a form of demand side management but LNG typically has the ability to provide additional natural gas supply at favorable locations within a potentially constrained distribution system. Satellite/portable LNG can therefore supplant the normal capacity upgrades performed on a distribution system by creating a new, portable supply point to maximize capacity possibilities.

## Diesel/Fuel Oil

There are four large volume industrial customers along the IFL that currently have the potential to use diesel or fuel oil as a natural gas supplement. The plants are able to switch their boilers over to burn oil and decrease a portion of their gas usage; the plants have fuel storage tanks onsite along with additional pipelines and equipment. Burning diesel or fuel oil in lieu of natural gas requires permitting from the local governing agencies, increases the level of emissions from the plant, and can have a lengthy approval process depending on the specific type of fuel oil used.

Out of the four industrial customers that currently have equipment to burn fuel oil currently two customers have the ability to supplement their natural gas usage, the other two customers lack the ability due to intentionally not renewing a permit or choosing not to purchase and store fuel oil at their facility. The estimated capital to install a diesel storage system is approximately $300,000 - $800,000 depending on usage requirements and days of storage. The estimated cost of diesel or fuel oil is between $2.90 - $3.90 per gallon depending on fuel grade and classification, time of purchase and quantity of purchase. The conversion cost to natural gas is roughly $2.20 to $3.00 per therm.

## Coal

Coal use is very limited as a resource for firm industrial customers within Intermountain's service territory. A coal user must have a separate coal burning boiler installed along with their natural gas burning boilers and typically must have additional equipment installed to transport the large quantities of coal within their facility. Regulations and permitting requirements can also be a challenge. Intermountain currently has a few industrial customers throughout the system that support coal backup systems, but currently have no firm industrial customers who can offset gas demand with coal.

The cost of coal in the northwest is approximately $75 per ton, including transportation and depending on the quality of the coal. Lower BTU coal would range from 8,000 – 13,000 BTU per pound while higher quality coal would range from 12,000 - 15,000 BTU per pound. This translates into a per therm cost of coal roughly at $0.35 - $0.42 plus permitting and equipment O&M costs.

## Wood Chips

Using wood chips as alternative fuel is a practice utilized by one large volume industrial customer on the IFL. In order to accommodate wood burning additional equipment must be installed, such as wood fired boilers and storage facilities for the wood chips. The wood is supplied from various tree clearing and wood mill operations that produce chips within regulatory specifications to be used as fuel. The chips are then transported by truck to location where the customer will typically store a two (2) to three (3) month supply. The wood fired boilers are currently used on a full-time basis in conjunction with natural gas boilers, and technically won't offset gas usage. For comparison purposes, the wood fired boilers, if used to replace natural gas for this specific industrial customer, could offset gas usage by approximately 5,000 therms per day. Unfortunately, this single customer does not have the ability to utilize any more wood fuel than they are currently using.

The cost of wood is continually changing based on transportation, availability, location and the type of wood processing plant that is providing the chips. Wood has a typical value of 4,500 BTU per pound, which converts into twenty two (22) pounds of wood being burned to produce one (1) therm of natural gas. An approximate cost of purchasing wood chips in the northwest is estimated at $75.00 - $100.00 per ton which converts to $0.82 - $1.10 per therm.

## Propane

Since propane is similar to natural gas the conversion to propane is much easier than a conversion to most other alternative resources. With the equipment, orifices and burners being similar to that of natural gas, an entire industrial customer load (boiler and direct fire) may be switched to propane. Therefore, utilizing propane on peak demand could reduce an industrial customer's natural gas needs by 100%. The use of propane requires onsite storage, additional gas piping and a reliable supply of propane to maintain adequate storage. Currently there are no industrial customers on the system that have the ability to use propane as a feasible alternative to natural gas; although, at least one customer is reviewing the possibility and planning to install propane redundancy within the next few years.

Capital costs for propane facilities can become relatively high due to storage requirements. Typical capital costs for a peak day send out of 30,000 therms per day, and the storage tanks required to sustain this load, are approximately $600,000 - $700,000. As with oil, storage facilities should be designed to accommodate a peak day delivery load for approximately seven (7) days. The average cost of propane ranges from $2.10 - $2.20 per gallon, which is a natural gas equivalent to $2.28 – 2.39 per therm. [NOTE: One gallon of propane is approximately 92,000 BTU]. Fixed O&M costs are approximately $50,000 - $100,000 per year.

## Satellite/Portable LNG Equipment

Satellite/Portable LNG equipment allows natural gas to be transported in tanker trucks in a cooled liquid form; meaning that larger BTU quantities can be delivered to key supply locations throughout the distribution system. Liquefied natural gas has tremendous withdrawal capability due to the natural gas being in a more dense state of matter. Portable equipment has the ability to boil LNG back to a gaseous form and deliver it into the distribution system by heating the liquid from -260ºF to a typical temperature of 50º - 70ºF. This portable equipment is available to lease or purchase from various companies and can be used for peak shaving at industrial plants or within a distribution system. Regulatory and environmental approvals are minimal compared to permanent LNG production plants and are dependent upon the specific location where the portable LNG equipment is placed. The available delivery pressure from LNG equipment ranges from 150 psig to 650 psig with a typical flow capability of approximately 2,000 - 8,000 therms per hour.

Intermountain Gas currently operates a portable LNG unit on the northern end of the Idaho Falls Lateral to assist in peak shaving the system. In addition to the portable equipment, Intermountain also has a permanent LNG facility on the IFL that is designed to accommodate the portable equipment, provide an onsite control building and allow onsite LNG storage capabilities. The ability to store LNG onsite allows Intermountain to partially mitigate the risk associated with relying on truck deliveries during critical flow periods. The LNG delivery risk is also reduced now that Intermountain has the ability to withdraw LNG from the Nampa LNG Storage Tank and can transport this LNG around the state in a timely manner. With Nampa LNG readily available the cost and dependence of third party supply is removed.

The cost of the portable LNG equipment is approximately $1 – $2.5 million with additional cost to either lease or purchase property to place the equipment and the cost of the optional permanent LNG facility. The fixed cost to lease the portable equipment is approximately $200,000 - $300,000 per month plus the cost of LNG.

## Capacity Upgrades

The three capacity upgrades discussed below do not reduce demand nor do they create additional supply points, rather they increase the overall capacity of a pipeline system while utilizing the existing gate station supply points.

## Pipeline Loop

Pipeline looping is a traditional method of increasing capacity within an existing distribution system. The loop refers to the construction of new pipe parallel to an existing pipeline that has, or may become, a constraint point. The feasibility of looping a pipeline is primarily dependent upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt, or steep and rocky terrain can greatly increase the cost to unjustifiable amounts when compared with alternative enhancement solutions

The potential increase in system capacity by constructing a pipeline loop is dependent on the size and length of new pipe being installed with typical increases in capacity ranging from 50,000 – 250,000 therms per day on large, high pressure laterals. The cost for a new pipeline installation of this magnitude is generally in the range of $7 - $20 million.

## Pipeline Uprate

A quick and sometimes relatively inexpensive method of increasing capacity in an existing pipeline is to increase the maximum allowable operating pressure of the line, usually called a pipeline uprate. Uprates allow a company to maximize the potential of their existing systems before constructing additional facilities and they're normally a low cost option to increase capacity; however, leaks and damages are sometimes found or incurred during the uprate process creating costly repairs. There are also safety considerations and pipe regulations that restrict the feasibility of increasing the pressure in any pipeline, such as the material composition, strength rating and relative location of the existing pipeline.

## Compressor Stations

Compressor stations are a third capacity-related option. They are typically installed on pipelines or laterals with significant gas flow and the ability to operate at higher pressures. Intermountain currently has two such transmission pipelines for which the installation of a compressor station can be practical: the Sun Valley Lateral and the Idaho Falls Lateral. Regulatory and environmental approvals to install a compressor station, along with engineering and construction time, can be a significant deterrent, but compressors can also be a cost effective, feasible solution to lateral constraint points. Compressor stations can be broken down into the following two (2) scenarios:

A single, large volume compressor can be installed on the pipeline when there is a constant, high flow of gas. The compressor is sized according to the natural gas flow and is placed in an optimal location along the lateral. This type of compressor will not function properly if the flow in the pipeline has a tendency to increase or decrease significantly. This type of station can have a price range of $3 - $5 million plus land, and a typical O&M cost will be in the range of $150,000 - $200,000 annually.

The second option is the installation of multiple, smaller compressors located in close proximity or strategically placed in different locations along a lateral. Multiple compressors are very beneficial as they allow for a large flow range, have some redundancy and use smaller and typically more reliable drivers and compressors. These smaller compressor stations are well suited for areas where gas demand is growing at a relatively slow and steady pace so that purchasing and installing these less expensive compressors can be done over time. This "just in time" approach allows a pipeline to serve growing customer demand for many years into the future while avoiding the single, rather large expenditure to purchase a larger station. However, high land prices or the unavailability of land may render this option economically or operationally infeasible. The cost of a smaller compressor station, excluding land, is estimated at $1.5 - $2.5 million with approximate O&M costs of $80,000 - $150,000 annually.

# DISTRIBUTION SYSTEM MODELING

Defined by the laws of fluid mechanics a natural gas pipeline creates pressure differential to move gas from one point to another on a system. Equal pressures throughout a closed pipeline system indicate that neither gas flow nor demand exist within that system. When gas is removed from some point on a system during the operation of natural gas equipment the pressure in the system at that point is then lower than the pressure upstream in the system. This pressure differential causes gas to move from the higher pressure point to the point of gas removal in an attempt to equalize the pressure throughout the distribution system. The same principle keeps gas moving from interstate pipelines to the LDC distribution systems. It is important that engineers design a distribution system in which the beginning pressure source from interstate pipelines, compressor stations or regulator stations within the system are adequately high and the transportation pipe specifications are designed appropriately to create a feasible and practical pressure differential when gas consumption occurs on the system. The goal is to maintain a system design where load demands do not exceed the system capacity; which is defined by the minimum pressure allowed at a determined point or points along the distribution system.

Due to the nature of fluid mechanics there is a finite amount of natural gas that can flow through a pipe of a certain size and length within a specified pressure; the laws of fluid mechanics are used to approximate this gas flow rate under these specific and ever changing conditions. This process is known as "pipeline system modeling." Ultimately, gas flow dynamics on any given pipeline lateral and/or distribution system can be ascertained for any set of known gas loading. The maximum system capacity is determined through the same methodology while calculating customer usage during a peak heating degree day.

In order to evaluate intricate pipeline structures a system model is created to assist an engineer in determining the flow capacity and dynamics of those pipeline structures. For example, before a large usage customer is incorporated into an existing distribution system the engineer must evaluate the existing system and then determine whether or not there is adequate capacity to maintain that potential new customer along with the existing customers, or if a capacity enhancement is required to serve the new customer. Modeling is also important when planning new distribution systems. The correct diameter of pipe must be designed to meet the requirements of current customers and reasonably anticipated future customer growth.

## Modeling Methodology

Intermountain utilizes a gas network modeling and analysis software program called SynerGEE Gas, distributed and supported by DNV-GL, to model all distribution systems and pipeline flow scenarios. The software program was chosen because it is reliable, versatile, continually improving and able to simultaneously analyze very large and diverse pipeline networks. Within the software program individual models have been created for each of Intermountain's various distribution systems including high pressure laterals, intermediate pressure systems, distribution system networks and large diameter service connections.

Each system's model is constructed as a group of nodes and facilities. Intermountain defines a node as a point where gas either enters or leaves the system, a beginning and/or ending location of pipe and/or non-pipe components, a change in pipe diameter or an interconnection with another pipe. A facility is defined in a system as a pipe, valve, regulator station, or compressor station; each with a user-defined set of specifications. The entire pipeline system is broken into three individual models for ease of use and to reduce the time requirements during a model run analysis. The largest model in use consists of 73,500 nodes and 77,300 facilities which are used along with additional model inputs to solve simultaneous equations through an iterative process.

SynerGEE can analyze a pipeline system at a single point in time or the model can be specifically designed to simulate the flow of gas over a specified period of time; which more closely simulates real life operation utilizing gas stored in pipelines as line pack. While modeling over time an engineer can write operations that will input and/or manipulate the gas loads, time of gas usage, valve operation and compressor simulations within a model, and by incorporating the forecasted customer growth and usage provided within this integrated resource plan Intermountain can determine the most likely points where future constraints may occur. Once these high priority areas are identified, research and model testing are conducted to determine the most practical and cost effective methods of enhancing the constrained location. The feasibility, timeline, cost and increased capacity for each theoretical system enhancement is determined and then placed into a comparison analysis and used within the IRP model.

# AVAILABLE AND POTENTIAL SYSTEM CAPACITY ENHANCEMENTS

Throughout previous sections of the IRP it has been shown that projected growth throughout Intermountain's distribution systems could possibly create capacity deficits in the future. Through the use of a gas modeling system that incorporates total customer loads, existing pipe and system configurations along with current distribution system capacities, each potential deficit has been defined with respect to timing and magnitude. If any such deficit occurs then the evaluation of system capacity enhancements are performed and provided as inputs to the optimization model.

The five identified Areas of Interest that were analyzed under design conditions are: the State Street Lateral, Central Ada County, Canyon County, the Idaho Falls Lateral and the Sun Valley Lateral. Each of these areas are unique in their customers served and their pipeline characteristics, and the optimization of each requires different enhancement solutions.

## State Street Lateral

The State Street Lateral is a sixteen mile stretch of high pressure, transmission main that begins in Caldwell and runs east along State Street serving Star, north Meridian, Eagle and into northern Boise. The lateral is fed directly from a gate station and is also back fed from another high pressure pipeline from the south. Much of the pipeline is closely surrounded by residential and commercial structures that create a difficult situation for construction and/or land acquisition, thus making a compressor station or LNG equipment less favorable. A complete review of the situation shows it is ideally suited to perform a pipeline retest; where the additional pressure at this location is obtainable and the Company has a chance to maximize the potential of its existing facilities before investing in new. The retest can be performed in phases over multiple years that provide increased capacity as actual growth is experienced, and the phasing will minimize the length of pipe that must be taken out of service each time. The State Street enhancement is not required within the five year projection of this IRP but it is continually being monitored and planned for within the company.

## Central Ada County

Central Ada County is a newly created Area of Interest that consists of high pressure, intermediate pressure and distribution pressure systems in an area of Ada County that contains higher than average customer usage trends and experiences higher levels of growth and development. The system currently has high pressure supplied from Chinden Blvd on the north side of the defined area and high pressure supplied from Victory Road on the south side of the defined area. The continued growth demands between these two separate systems have begun to tax the Chinden high pressure pipeline and the smaller lines supplied from Chinden. The system enhancement solution selected for this situation is to install a new 8" pipeline on Cloverdale Road that will connect the Victory system, which contains surplus capacity, to a branch of the Chinden system; which will alleviate the current demand from Chinden. At this time the Victory and Chinden systems have different operating pressures and can't be directly connected, so an isolation valve will be used to separate the systems while still maintaining new load on the Victory pipeline. This system enhancement will setup Central Ada County for future enhancement opportunities where the Victory pipeline could be uprated to match the Chinden pipeline; which will create a contiguous, looped system through most of Central Ada County.

## Canyon County

Canyon County's capacity was increased in 2013 when the Parma Lateral was replaced with a larger pipeline, and since the new pipeline was installed in a location closer to existing pipe that is part of the Canyon County area, it was determined that the two lines be connected. With the new connection into Canyon County, this AOI was upgraded from a single supply system to a dual supply, back fed system that can support additional customer growth. Due to this system manipulation the proposed enhancement in the 2012 IRP, the 8" Orchard-Farmway Loop, is no longer required, and the Canyon County area does not require an enhancement within the 2014 IRP five year projection.

## Idaho Falls Lateral

The Idaho Falls Lateral began as a 52 mile, 10" pipeline that originated just south of Pocatello and ended at the city of Idaho Falls. The IFL was later extended farther to the north with 8" pipe for an additional 52 miles to serve the growing towns of Rigby, Rexburg and St. Anthony. As demand has continually increased along the IFL Intermountain Gas has been completing capacity enhancements for the past 20 years; including, compression (now retired), a satellite LNG facility, 40 miles of 12" pipeline loop, and 34.5 miles of 16" pipeline loop.

In 2012 Intermountain completed the addition of Phase V, a project that extended 15.5 miles of 16" high pressure pipeline to the north of Idaho Falls and increased the year round capacity available on the lateral. With the recent addition of new industrial customer demand of the IFL, Intermountain's current integrated resource plan utilizes the Rexburg LNG facility for peak day shaving starting in 2017 and currently plans to install a second storage tank in 2018. Aside from peak shaving LNG there are no system enhancement requirements for the five year forecast.

## Sun Valley Lateral

The Sun Valley Lateral is a 70 mile long 8" high pressure pipeline that has almost its entire demand at the far end of the lateral away from the gas source. Obtaining land in close proximity to this customer load center is either very expensive or simply unobtainable. Throughout the years Intermountain has uprated and upgraded this existing lateral, and most recently installed a compressor station towards the south end of the lateral, in order to maintain capacity and increase flow toward the north end of the system. These pipeline enhancements and compression on the SVL have provided enough capacity for the lateral to serve Intermountain's five year forecast horizon; the SVL remains in the IRP due to continued observation and planning for this unique system.

# THE EFFICIENT AND DIRECT USE OF NATURAL GAS

## NATURAL GAS AND OUR NATIONAL ENERGY PICTURE

According to the American Gas Association, in the United States natural gas currently meets nearly 25% of the nation's energy needs, providing energy to more than 68 million American homes. The residential market comprises 21% of total U.S. natural gas consumption. Over 5,000,000 commercial customers also use natural gas for their energy needs, consuming 14% of our nation's annual throughput. Roughly 193,000 industrial and manufacturing sector customers use natural gas in their processes, consuming 31% of the U.S. annual total. And in another fast-rising sector, 5,500 electric-power-generating units produce 27% of total U.S. electricity, consuming the remaining 34% of annual U.S. demand.

The simple reason for the widespread use of this energy source is: natural gas is the cleanest and most efficient fossil fuel, period. Continued expansion of natural gas usage can help address several environmental concerns simultaneously, including smog, acid rain, and carbon footprint.

Furthermore, 98.5% of the natural gas used in the United States comes from North America, where supplies are abundant. The 2.1-million-mile underground natural gas delivery system has an outstanding safety record, and is reliably capable of delivering natural gas, regardless of the weather.

Thus, for all the right reasons, the demand for natural gas has risen. In the past, its price had risen markedly with the increased demand. But now, due to significant new domestic natural gas discoveries in North America (and in part due to our still slowly-recovering economy), the wellhead price of natural gas has dropped to levels not seen since 2002. Furthermore, the previous price-volatility exhibited over the last 10 years has calmed considerably.

Natural gas is now even more plentiful in North America, with an estimated 100 year supply at current consumption levels. Furthermore, when new "unconventional" supplies such as coal bed methane are included in forecasts, U.S. natural gas supplies could be extended several hundred more years.

Even with this plentiful supply, and lower, more stable prices, it remains vital that all natural gas customers use the energy as wisely and as efficiently as possible.

## NATURAL GAS EQUIPMENT EFFICIENCY

Technology has given us many new and more efficient ways to meet our energy needs without sacrificing the environment. Over the recent years, new natural gas residential and commercial HVAC equipment and appliances have become far more efficient, as Federal and State equipment efficiency standards have taken effect. And in the existing customer group, as older, less-efficient equipment wears out, it's replaced with these newer, more efficient units. Thus, the entire natural gas user base grows more efficient every year.

The adoption of more energy efficient building codes and standards – new homes and commercial structures built to higher standards driven by Federal and State codes - has meant far more efficient use of natural gas. As with the replacement of older equipment mentioned above, older housing and commercial units are being upgraded to higher efficiency standards. Annual residential gas usage per customer dropped by 25% between 1996 and 2010. Overall, the average U.S. residential customer uses 40% less natural gas than it did in 1974, thanks largely to the aforementioned efficiency improvements. Average annual IGC residential customer gas consumption has dropped by 13% since 2000.

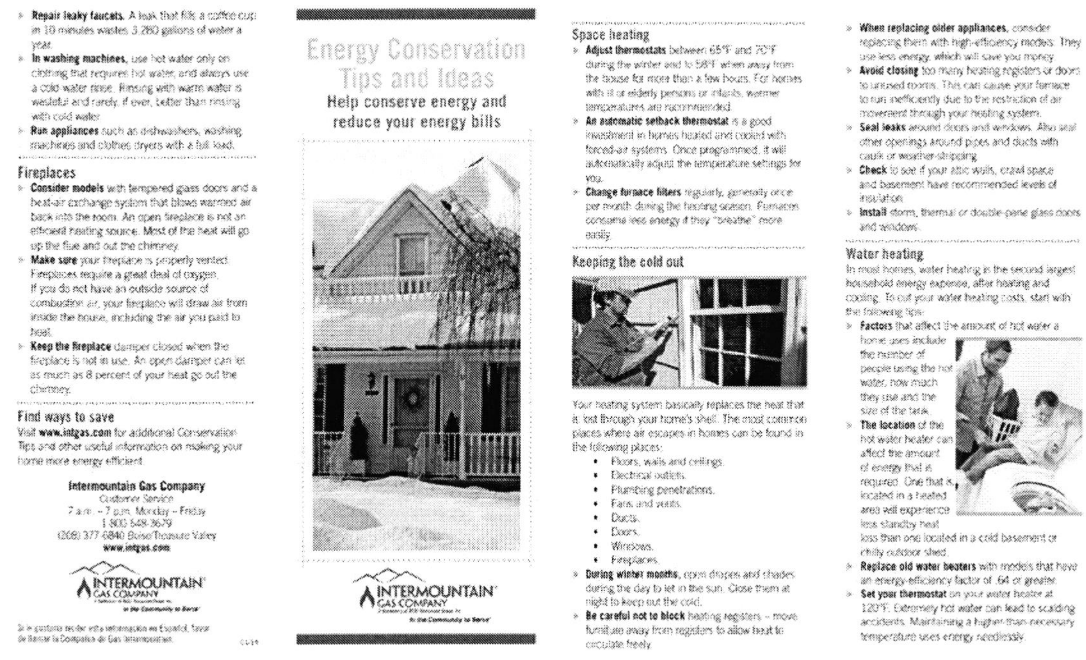
Natural gas equipment efficiency makes economic sense in today's new energy era, and IGC will continue to encourage new residential and commercial technologies, as they become available.

## NATURAL GAS CONSERVATION CUSTOMER EDUCATION

### Website

On our website, www.intgas.com, residential and small commercial customers can obtain detailed information regarding energy conservation at home or their business. Large-volume/Industrial customers have their own website from which they can obtain real-time gas consumption information.

Also at the website, customers can view our Energy Conservation Brochure, which was also mailed to all our +327,000 core-market customers in January 2014.



- **Repair leaky faucets.** A leak that fills a coffee cup in 10 minutes wastes 3,280 gallons of water a year.
- **In washing machines,** use hot water only on clothing that requires hot water, and always use a cold-water rinse. Rinsing with warm water is wasteful and rarely, if ever, better than rinsing with cold water.
- **Run appliances** such as dishwashers, washing machines and clothes dryers with a full load.

**Fireplaces**

- **Consider models** with tempered glass doors and a heat-air exchange system that blows warmed air back into the room. An open fireplace is not an efficient heating source. Most of the heat will go up the flue and out the chimney.
- **Make sure** your fireplace is properly vented. Fireplaces require a great deal of oxygen. If you do not have an outside source of combustion air, your fireplace will draw air from inside the house, including the air you paid to heat.
- **Keep the fireplace** damper closed when the fireplace is not in use. An open damper can let as much as 8 percent of your heat go out the chimney.

**Find ways to save**

Visit **www.intgas.com** for additional Conservation Tips and other useful information on making your home more energy efficient.

**Intermountain Gas Company**
Customer Service
7 a.m. – 7 p.m. Monday – Friday
1 800 548-3679
(208) 377-6840 Boise/Treasure Valley
**www.intgas.com**

INTERMOUNTAIN GAS COMPANY

Energy Conservation Tips and Ideas
Help conserve energy and reduce your energy bills

INTERMOUNTAIN GAS COMPANY

**Space heating**

- **Adjust thermostats** between 65°F and 70°F during the winter and to 58°F when away from the house for more than a few hours. For homes with ill or elderly persons or infants, warmer temperatures are recommended.
- **An automatic setback thermostat** is a good investment in homes heated and cooled with forced-air systems. Once programmed, it will automatically adjust the temperature settings for you.
- **Change furnace filters** regularly, generally once per month during the heating season. Furnaces consume less energy if they "breathe" more easily.

**Keeping the cold out**

Your heating system basically replaces the heat that is lost through your home's shell. The most common places where air escapes in homes can be found in the following places:

- Floors, walls and ceilings.
- Electrical outlets.
- Plumbing penetrations.
- Fans and vents.
- Ducts.
- Doors.
- Windows.
- Fireplaces.

- **During winter months,** open drapes and shades during the day to let in the sun. Close them at night to keep out the cold.
- **Be careful not to block** heating registers – move furniture away from registers to allow heat to circulate freely.
- **When replacing older appliances,** consider replacing them with high-efficiency models. They use less energy, which will save you money.
- **Avoid closing** too many heating registers or doors to unused rooms. This can cause your furnace to run inefficiently due to the restriction of air movement through your heating system.
- **Seal leaks** around doors and windows. Also seal other openings around pipes and ducts with caulk or weather-stripping.
- **Check** to see if your attic walls, crawl space and basement have recommended levels of insulation.
- **Install** storm, thermal or double-pane glass doors and windows.

**Water heating**

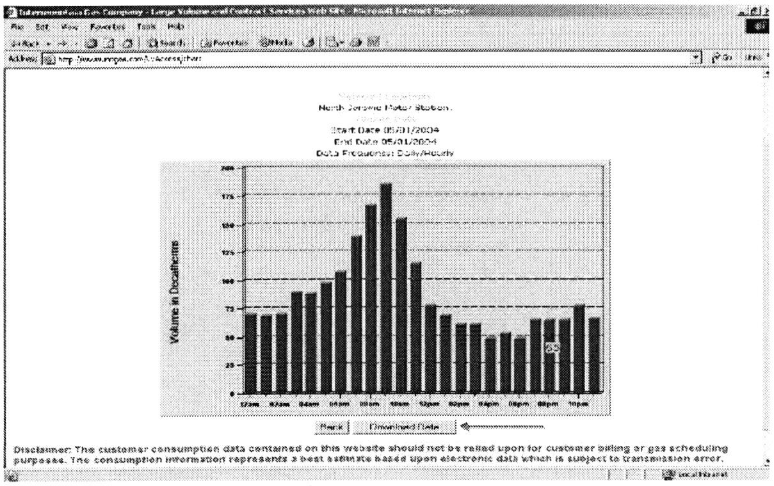
In most homes, water heating is the second largest household energy expense, after heating and cooling. To cut your water heating costs, start with the following tips:

- **Factors** that affect the amount of hot water a home uses include the number of people using the hot water, how much they use and the size of the tank.
- **The location** of the hot water heater can affect the amount of energy that is required. One that is located in a heated area will experience less standby heat loss than one located in a cold basement or chilly outdoor shed.
- **Replace old water heaters** with models that have an energy-efficiency factor of .64 or greater.
- **Set your thermostat** on your water heater at 120°F. Extremely hot water can lead to scalding accidents. Maintaining a higher-than-necessary temperature uses energy needlessly.

In addition to bill paying and other services, IGC customers can also access their individual billing and gas consumption history on the website. Customers can enroll online or by phone. The process is easy, and access is immediate. IGC customer communications, mass-media advertising, website, and marketing information all encourage customers to consider high-efficiency equipment when making their equipment purchase or upgrade decisions.

Intermountain Gas Company's Industrial Website was designed to allow the industrial customer access to the most up-to-date natural gas usage information at their location. The site is accessible via the internet using a specific logon name and password, making the information on each customer site-specific. It contains a great deal of information useful to the large volume customer. They can access information as to the different services and applicable tariffs.

## Viewing Consumption



***Note: Usage information is shown in Decatherms***

There are several tools to review, evaluate, and analyze the natural gas consumption at their specific facility. The meter reads are taken hourly, and sent via radio communication to our Gas Control Center. Once this information is in our system, it is available for viewing on the website. This is especially useful in tracking and evaluating energy saving measures and new production procedures. History may be downloaded as far back as January 1994 and all information is available on an hourly, weekly, monthly, and annual basis.

IGC strives to keep this site in the most usable format for the customers, so a "feedback" button is also included on the site to let us know how best to fulfill their needs.

Intermountain's customer contact and marketing personnel are equipped to assist current and potential customers with evaluating the advantages of installing high-efficiency gas equipment where possible.

## Education

IGC personnel participate in public safety training and energy conservation seminars around the state. Intermountain has a long history of promoting the efficient use of natural gas by our customers. Over the years, IGC has offered rebates and incentives for the installation of energy saving devices such as pilotless furnace ignition systems, furnace flue dampers, and still to this day, a high-efficiency (90%) furnace conversion rebate.

IGC is a member of the Energy Solutions Center Renewable Energy Workgroup.

IGC is an active voice in Idaho's legislative process as the lawmakers consider new, higher-efficiency building and energy codes.

## Research

IGC has provided financial assistance to the University of Idaho Integrated Design Lab to further that entity's energy efficiency research and training.

The Gas Technology Institute continues to perform important ongoing research and development work in the gas equipment arena, from residential to large industrial. The Gas Technology Institute (GTI) is our nation's leader in ongoing natural gas R&D, as well as the deployment and commercialization of new gas efficiency technologies. IGC has participated in GTI R&D projects, and will continue that collaboration as the opportunities arise.

In the Fall of 2014, GTI and IGC will collaborate on cold-climate testing of the NextAire natural gas heat pump. The NextAire is projected to have a heating efficiency of 1.2 COP; and to save at least 30% in O&M costs while using 80% less electricity when compared to electric heat pump equipment. Furthermore, since the NextAire does not require a separate cooling tower, a significant reduction in water consumption is also expected. A 15-ton commercial unit will be installed at the IGC Western Region building in Boise. The test period will run for 18 months through two winter heating seasons.

As of Summer 2014, IGC is also working with GTI to collaborate with the Northwest Energy Efficiency Alliance (NEEA) on Idaho field testing of a residential Gas Heat Pump Water Heater (GHPWH). This newly-designed unit is projected to operate at twice the efficiency of conventional gas-fired storage water heaters. The testing in Idaho will evaluate the unit in the typical garage water-heater location so common in Idaho residences, and would begin Fall 2014.

## ENERGY EFFICIENCY THROUGH THE DIRECT USE OF NATURAL GAS

Aside from technical improvements in equipment efficiency, and conservation-minded customer behavior, one overriding factor in efficient natural gas usage is the concept of direct use, whenever possible. "Direct use" refers to employing natural gas at the end-use point for space heat, water heating, and other applications, as opposed to using natural gas to generate electricity to be transmitted to the end-use point and then employed for space or water heating.

As electric generating capacity becomes more constrained in the Pacific Northwest, additional generating capacity will primarily be natural gas fired. While development of additional hydro or coal-fired generating facilities may be nearly impossible, those already in place will continue to operate at generally full capacity for many years to come. Direct use will mitigate the need for future generating capacity. If more homes and businesses use natural gas for heating and commercial applications, then the need for additional generating resources will be reduced. At times of excess capacity, water storage normally used for generating power, can be released for additional irrigating, aquifer recharging, fish migration, and navigation uses.

This more efficient, direct use obviously translates into a much lower carbon footprint. First, let's look at coal-fired electricity, which makes up a sizeable portion of our region's power supply:

Coal-fired, sub-critical steam power plants such as Jim Bridger are 40% efficient at best (a 40% heat rate). The typical sub-bituminous coal used there has a heat-content of 18 million btu's per ton (9,000 btu's per pound). When burned, this ton of coal produces over 3,700 pounds of $CO2$ into the atmosphere (1.85 lbs of $CO2$ per pound of coal burned). At the facility's 40% heat rate, for each kilowatt-hour (3,413 btu's) of electricity produced, 8,532.5 btu's worth of coal, or about .948 of a pound of coal must be burned. So, 1 kwh of electricity from Bridger emits 1.75 lbs of $CO2$. Delivering the same amount of energy to the natural gas direct user (3,413 btu's), requires .03413 of a therm of natural gas, emitting .41 of a pound of $CO2$ when burned. So, natural gas used directly instead of coal-fired electricity has a 76% smaller carbon footprint than the electricity from a coal-fired plant.

Now, let's consider natural gas powered electrical generation plants:

Natural gas fired combustion turbines like Langley Gulch, are generally 60% efficient at best. Furthermore, transmission and distribution losses can total another 5 – 10%. Effectively, half of the energy originally contained in the natural gas has been lost before arriving at the point of use. High-efficiency natural gas furnaces are rated at up to 96% efficiency. New gas water heater efficiency standards provide for 60% to 80% efficiency. In terms of the carbon footprint, a therm of natural gas (100,000 btu's) delivered directly to the end user emits roughly 12 lbs of $CO2$ into the atmosphere. The equivalent amount of electricity, 100,000 btu's, or just under 30 kilowatt hours emits roughly 24 lbs of $CO2$, again considering a 60% generating plant heat rate and 10% transmission line losses. So, in this case, direct use of natural gas, where possible, has a 50% smaller carbon footprint than electricity from a natural gas-fired plant.

So, from a resource and environmental basis, direct use makes the most sense. More energy is delivered using the same amount of natural gas, resulting in lower cost and lower $CO2$ emissions spread out over a far wider airshed. This direct, and therefore, more-efficient natural gas usage will serve to keep natural gas prices, as well as electricity prices, lower in the future. Our success in marketing to

Idaho's residential new construction market, where we have a +90% penetration rate along our service mains, is a prime of example the direct use of natural gas, where possible.

To illustrate the significant role that IGC plays in southern Idaho's total energy picture, IGC has over 295,000 residential customers. The average annual therm usage of an IGC space-heating-only customer is 491 therms. That equates to a total residential therm usage of approximately 145,000,000 therms in a year. If the total was used at the Federal efficiency minimum of 78%, then (145,000,000 X .78 = 113,100,000 therms X 100,000 btu's/therm) or 11,310,000,000,000 btu's were generated. (A therm is 100,000 btu's of heat.) There are 3,412 btu's in a kilowatt-hour. At 100% efficient electric resistance heat efficiency, this means that the IGC residential space-heat customers would use the equivalent of (11,310,000,000,000 / 3,412) or 3,314,771,395 kilowatt-hours in a year to heat their homes. This is the same as 3,314,771 megawatt hours of power saved, year in, year out.

According to their 2013 Annual Report found on their website, Idaho Power's total annual residential megawatt hour sales for 2013 were 5,365,000. If the aforementioned 295,000 IGC residential customers were using electric space heat instead of natural gas, Idaho Power's total residential sendout would rise to 8,679,771 mWh, a 61% increase, requiring considerable additional generation and transmission facilities.

In peak terms, if these 295,000 IGC customers had electric furnaces with 25kw capacity, and just 1/3 of them were operating simultaneously during a cold-weather winter peak, there would be an additional winter peak load of 2,458 megawatts. Again, according to their website, Idaho Power recently experienced a December 2013 winter peak load of 2,482 megawatts. Without the direct use of natural gas to heat these 295,000 homes, Idaho Power's winter peak load could reach 4,940 megawatts, a nearly 100% increase! This additional 2,458 megawatt peak load would be the equivalent of more than <u>eight</u> 300 megawatt natural gas-fired electric generating facilities, like Langley Gulch, all running at full throttle. This would probably also require a substantial increase in transmission facilities to handle this peak load, since it would be well above the Idaho Power July 2013 Summer peak of 3,407 megawatts.

In terms of recently-shed electric load, just since 1991, IGC has converted over 28,000 residential electric heating customers to natural gas. Using the space heating consumption rates shown above, these gas conversions save about 403,000 megawatt hours of residential sendout per year. In winter peak terms, using the "1/3 operating simultaneously" example in the paragraph above, 233 megawatts of peak load is saved. This "year in, year out" electrical conservation is realized at no cost to the electric customers in Southern Idaho. If residential water heating were included, the annual sendout figures would rise by at least 25%.

In terms of summer energy consumption, IGC residential water heaters also provide significant relief to the ever-growing hot weather electric demand. IGC has over 229,000 RS-2 (space and water heat) customers. If, instead these were 229,000 electric water heaters each rated at 9,000 watts, or 9kW, this would amount to 2,061 megawatts of total load. If this total amount was treated as shifted or curtailed, per the Utah Power and Light irrigation load control credit rider of some years ago, the credit value would have ranged from $2,025,000 in September to $4,724,000 for July. But the summer water heating load curtailment and shifting provided by the IGC water heater customers has come at no cost to electric utilities or their customers.

# LOST AND UNACCOUNTED FOR NATURAL GAS MONITORING

As part of an ongoing commitment to the efficient use of natural gas, Intermountain Gas Company has been pro-active in finding and eliminating sources of Lost and Unaccounted For (LUAF) natural gas. As the name suggests, LUAF is the difference between volumes of natural gas delivered to Intermountain's distribution system and volumes of natural gas billed to Intermountain's customers. Intermountain has a standing inter-disciplinary team that reviews the LUAF audit processes currently in place, investigates potential sources of LUAF, and takes remedial action as needed to continue to keep Intermountain's LUAF levels low.

In the early 2000's, Intermountain reevaluated its billing attributes in an effort to reduce the amount of LUAF occurring. As part of this reevaluation, Intermountain made the following changes:

- Increased weather points from 5 locations to 10 locations.
- Changed average daily temperature calculation from a simple daily high/daily low average to an hourly temperature for a 24-hour period averaged into a daily temperature average
- Created billing and meter audits

The weather and temperature changes provide for a better temperature component of the billing factor used to calculate customer energy consumption.

Billing audits to identify Low Usage and Zero Usage are performed with each billing cycle. Low Usage Reports are used to compare billed consumption against that same customer's historical usage patterns. If the current month's billed consumption appears low in relation to historical usage patterns, the account is flagged. A courtesy phone call is then made to determine if there is a valid reason for the lower-than-normal usage, or a check-for-dead order is generated for the following day and a service technician is dispatched to field test the meter for functionality.

Zero Usage Reports help to identify those meters where usage is arguably taking place, but not registering on the meter. On those accounts that are not documented as being "off" by the system, a check-for-dead order is generated and a service technician is dispatched to field test the meter for functionality.

Reports are also generated that review billed consumption for a given meter size. There should arguably be a correlation between the customer's billed volumes and the size of the meter installed to serve that customer. These types of correlated audits sometimes identify malfunctioning meters and at other times identify a problem with the programming in place that translates metered consumption to billed consumption.

Intermountain also works to ensure billing accuracy of newly installed meters. A Service Tech (different from the Service Tech that installed the meter) performs a Meter Audit on meter classes with drive rates or billing pressures that don't have a one-foot drive rate and four ounce billing pressure, respectively. These audits are performed to ensure that the correct drive rate and billing pressure are programmed for the meter and billing system to avoid billing errors. Any corrections are made prior to the first bill going out.

Intermountain also compares on a daily and monthly basis its telemetered usage versus the metered usage that Northwest Pipeline records. These frequent comparisons enable Intermountain to find any material measurement variances between Intermountain's distribution system meters and Northwest Pipeline's meters.

Meter rotations are also an important tool in keeping LUAF levels low. Intermountain conducts regular samples of its meters to test for accuracy. A rotation plan is developed by applying the "ANSI/ASQ Z1.9 – 2003 Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming" standard for sampling to the eligible families of meters in service. Sample meters are pulled from the field and brought to the meter shop for testing. During testing, meters are checked for registration accuracy and consistency of measurement between the mechanical meter index and a benchmark proving piece of equipment (Sonic Nozzle Auto Prover – SNAP). The results of this testing are evaluated by meter family to determine the pass/fail of a family based on sampling procedure allowable defects. If the sample audit determined that the accuracy of certain batches of purchased meters was in question, additional targeted samples would take place and any necessary follow up remedial measures would be taken.

In addition to these regular meter audits, Intermountain also identifies the potential for incorrectly sized and/or type of meter in use by our larger industrial customers. Some industrial customers consume natural gas differently over time as the economy changes, the customer institutes plant and equipment improvements, or conservation measures are implemented. A meter size and/or type which may have once been warranted at the customer's premise may no longer be applicable and a change in installed meter size and/or type might be necessary. Many of Intermountain's large industrial customers have remote measurement devices installed at their premise which facilitate a monthly comparison to the billed volumes as determined by the customer's meter. If a discrepancy exists between the two measured volumes, remedial action is taken.

On a regular and programmed basis, Intermountain technicians check Intermountain's entire distribution system for natural gas leaks using sophisticated equipment that can detect even the smallest leak. When such leaks are identified, which is very infrequently, remedial action is immediately taken. Unfortunately, human error by an outside contractor or even a home owner sometimes leads to unintentional damage to our distribution system. When such a gas loss situation occurs, an estimate is made of the escaped gas and that gas then becomes "found gas" and not "lost gas".

## Audit Results

| | 2011 | 2012 | 2013 |
|---|---|---|---|
| Dead Meters | 795 | 513 | 796 |
| Drive Rate Errors | 14 | 3 | 3 |
| Pressure Errors | 8 | 8 | 13 |
| Gas loss occurrences due to line damage | 154 | 177 | 163 |

Intermountain continues to monitor LUAF levels and looks for additional opportunities keep its LUAF rate among the lowest in the natural gas distribution industry.

# DEMAND-SIDE MANAGEMENT

In their Order regarding the 2010 IRP, the Commission identified one area regarding DSM they would like to see IGC improve upon in the 2012 IRP:

"Intermountain should consider any DSM programs for Core-market customers that have the potential to be cost-effective in promoting and enticing energy savings. As recommended by the Idaho Conservation League, Intermountain should carefully consider all DSM programs that are available to encourage customers to use natural gas efficiently, and Company reviews of programs must be included in its IRPs. Its IRPs in the future must reflect that it has evaluated DSM programs for all customer groups."

The analysis, selection, and potential deployment of natural gas efficiency and conservation measures is known as Demand-Side Management, or DSM. The goal of Intermountain's DSM analysis was two-fold: 1) to ascertain whether achievable and economically viable DSM could provide a reliable resource in IGC's peak-load management, and 2) to facilitate year-round improvements in natural gas usage.

DSM includes behavior modification, building-envelope improvement, and higher-efficiency natural gas equipment. One particularly important consideration is the comparison of the cost of DSM employed to reduce the growing demand vs. the cost of building additional infrastructure, purchasing pipeline capacity, or purchasing the natural gas commodity, to meet the growing demand.

The Total Resource Cost test is a widely-used measure of DSM cost. In that model, the capitalized annual cost of a DSM measure is divided by the annual therms saved over the expected life of the measure. The peak therms saved can also be applied to this equation. In either instance, the unit (per therm) cost of reducing demand growth can be compared to the unit cost (again, per therm) of building capacity and purchasing supply to meet the additional demand. Again, either from a year-round, or peak-day perspective.

The Intermountain Gas Company DSM process consisted of four steps:

1. Establishment of broad DSM Objectives
2. Ascertain and address a full spectrum of DSM opportunities
3. Perform an assessment of DSM programs

## DSM Objectives

- Provide customer service
- Accommodate high efficiency and off-peak load growth
- Limit the need for new staffing resources
- Maintain competitive position as low-cost energy provider
- Provide environmental benefits
- Focus solely on the most cost-effective DSM measures

## Addressing a Full Spectrum of Potential DSM Programs

In 2007, IGC commissioned a DSM study by Navigant Consulting (Navigant) to assist in the discovery and evaluation of a full spectrum of DSM opportunities. An important requirement of Navigant's work was that only established natural gas DSM measures being employed by other gas utilities were to be catalogued and evaluated. IGC provided Navigant with customer segmentation and distribution data, service-area market assumptions, and other pertinent data. Navigant's work was very thorough, and various measures were listed, along with their various costs, market deployment potential, peak savings, and year-round gas savings. DSM programs listed were also broken down by their market potential in the geographically-specific laterals, as described elsewhere in the IRP.

The programs listed in Navigant's work included ductwork improvements, appliance efficiency upgrades, insulation improvements, ventilation upgrades, improved windows, and other building envelope measures.

For the 2012 IRP analysis, this Navigant study was updated to reflect current market conditions and efficiency assumptions.

## Assessment of Potential DSM Programs

In assessing the potential DSM options, Intermountain chose to first consider programs which would not duplicate other programs, would not be redundant with regard to codes or other regulations, and would provide a truly additional energy savings. Cost-effectiveness was important, but the measures selected had to impact the greatest number of customers, and their most significant gas usage.

As previously mentioned, building techniques and codes, and improved appliance technology have resulted in homes using 32% less gas than in 1980. This is the market. Additional upgrades, such as ENERGY STAR, typically provide monthly utility cost savings that outweigh the additional monthly mortgage payment to cover their higher cost. Therefore, new-home buyers already have a financial incentive to include enhanced energy efficiency features in their new home.

Since these new-construction efficiency measures already offer a significant financial incentive, IGC proposes to continue its promotion of high-efficiency new construction in our advertising, builder association participation, and through our ENERGY STAR Utility Partner activities. This market-based approach makes the most sense in the new-construction arena. Our advertising promotion of high-efficiency new homes and ENERGY STAR is ongoing.

In the 2010 IRP, IGC proposed the following DSM programs be implemented in calendar year 2011 as a pilot program on the Idaho Falls Lateral. No regulatory filing was undertaken, and the proposed programs 2, 3, and 4 have not been implemented.

1. Continue the existing $200 rebate for customers converting to natural gas if they purchase a 90%-or-greater efficiency furnace.

2. Begin a new program to provide a $30 rebate if a customer converts to a .64 or greater EF natural gas water heater from another source.

3. Implement a new program to provide a $200 rebate if an existing customer replaces a below-90%-efficiency furnace with a 90%-or-greater efficiency natural gas furnace.

4. Implement a new program to provide a $30 rebate if an existing customer replaces an existing natural gas water heater with a .64 or greater EF gas water heater.

Intermountain's $200 furnace rebate program outlined in (1) above is still available. The total rebates issued in 2011 were $35,600, $43,000 in 2012 and $46,400 in 2013. This program will continue in its present form.

Since the 2010 IRP, there have been significant changes in the natural gas market. Starting with our October 2010 Purchased Gas Adjustment (PGA), IGC has lowered its core-market gas prices three out of the last four years to the RS1, RS2, and GS1 customer classes by 7.4%, 9.4%, and 8.4%, respectively. Furthermore, these reductions followed two preceding PGA price reductions totaling nearly 30% for the core-market. As a result of this nearly 40% residential price reduction since 2008, the residential DSM programs previously analyzed for pilot implementation still will not provide the cost-benefits estimated under the significantly higher gas prices seen by IGC in recent years earlier. Furthermore, natural gas prices are expected to remain at these lower levels at least through IGC's next IRP filing.

And while the U.S DOE's efforts to set new rules mandating higher, region-based minimum efficiency standards for residential HVAC appliances are currently being held up in the courts, natural gas water heater efficiency standards are increasing. Currently, U.S. gas water heater efficiency standards mandate .67 Energy Factor (EF) for 40 gallon units. Beginning April 2015, 40 gallon natural gas water heaters will be required to have a .675 EF.

In their Order regarding the 2012 IRP, the Commission added no other stipulations or recommendations regarding IGC's evaluation of DSM programs.

IGC will continue the existing $200 rebate for customers converting to natural gas if they purchase a 90%-or-greater efficiency furnace.

IGC remains committed to promoting the efficient, direct use of natural gas wherever possible, and will continue to promote the wise use of all energy.

## Conclusion

Ever-increasing and more pervasive energy standards and practices will continue to improve the energy efficiency of Intermountain Gas Company's customers. Intermountain will continue in its active role promoting the wise and efficient use of natural gas, and in carefully monitoring LUAF levels. The wise, direct use of natural gas in the coming years will help keep overall energy costs low in southern Idaho, help protect the environment, and ensure ample, lower-cost electricity for its many other valuable uses.

# LOAD DEMAND CURVES

The culmination of the demand forecasting process is aggregating the information discussed in the previous sections into a forecast of future load requirements. As the previous sections illustrate, the customer forecast, design weather, core usage data, industrial usage forecast and price scenarios are all key drivers in the development of the load demand curves.

The IRP customer forecast provides a total company daily projection through Planning Year (PY) 2019 and includes a forecast for each of the five regional segments of the distribution system. Each forecast was developed under each of three different customer growth scenarios: base case, high growth and low growth.

The development of a design weather curve - which reflects the coldest historical weather patterns across the service area - provides a means to distribute the core market heat sensitive portion of the Intermountain's load on a daily basis. Applying Design Weather to the residential and small commercial usage per customer forecast creates core market usage-per-customer under design weather conditions. That combined with the applicable customer forecast and price scenarios yields a daily core market load projection through PY19 for company total as well as for each regional segment. Similar normal weather scenario modeling was also completed.

As discussed in the Industrial Forecast section, the forecast also incorporates the industrial CD from both a company-wide perspective (interstate capacity) and the regional segments (distribution capacity). When added to the core market figures, the result is a grand total daily forecast for both gas supply and capacity requirements including a break-out by regional segment.

Peak day sendout under each of these customer growth scenarios was measured against the currently available capacity to project the magnitude, frequency and timing of potential delivery deficits, both from a total company perspective and a regional perspective.

Once the demand forecasts were finished and evaluation complete, the data was arranged in a fashion more conducive to IRP modeling. Specifically, the daily demand data for each individual forecast was sorted from high-to-low to create what is known as a Load Demand Curve (LDC). The LDC incorporates all the factors that will impact Intermountain's future loads. The LDC is the basic tool used to reflect demand in the IRP Optimization Model.

It is important to note that the Load Demand Curves represent **existing** resources and are intended to identify potential capacity constraints and to assist in the long term planning process.

### Design PY 15 – PY 19 Customer Growth Summary Observations

**Idaho Falls Lateral**

The Low Growth customer forecast projects an increase in customers of 2,955 through PY19 (Oct 1, 2014 to Sep 30, 2019) which corresponds to an annualized average growth rate of 1.09%. Base Case customers increase by 6,937 customers (2.56%) and High Growth customers increase by 12,927 customers (4.78%).

### Sun Valley Lateral

The Low Growth customer forecast (PY15 – PY19) projects an increase of 293 customers (.5% annualized growth rate), Base Case customer forecast increases by 724 customers (1.24% annualized growth rate), and High Growth customer forecast shows an increase of 1675 customers (2.87% annualized growth rate).

### Canyon County Area

The Low Growth customer Forecast for Canyon County (CC) reflects an increase of 6,591 customers during this IRP period (PY15 – PY19), which is an annualized growth rate of 2.65%. The Base Case customer forecast for CC increases by 8,883 customers (3.57% annualized growth rate) over the 5-year period. The High Growth customer forecast shows an increase of 12,850 customers (5.17% annualized growth rate).

### State Street Lateral

The Low Growth customer Forecast for the State Street Lateral (SSL) reflects an increase of 2,388 customers during this IRP period (PY15 – PY19), which is an annualized growth rate of 1.03%. The Base Case customer forecast for SSL increases by 5,328 customers (2.30% annualized growth rate) over the 5-year period. The High Growth customer forecast shows an increase of 12,195 customers (5.26% annualized growth rate).

### Central Ada Area

The Low Growth customer Forecast for the State Street Lateral (CAA) reflects an increase of 2,762 customers during this IRP period (PY15 – PY19), which is an annualized growth rate of 1.15%. The Base Case customer forecast for CAA increases by 6,279 customers (2.62% annualized growth rate) over the 5-year period. The High Growth customer forecast shows an increase of 14,411 customers (6.01% annualized growth rate).

### Total Company

The Low Growth customer forecast (PY15 – PY19) projects an increase of 19,718 customers (1.20% annualized growth rate), the Base Case customer forecast increases by 39,345 customers (2.39% annualized growth rate), and the High Growth customer forecast shows an increase of 77,759 customers (4.71% annualized growth rate).

Using the LDC analyses, Intermountain will be able to anticipate changes in future demand requirements and plan for the use of existing resources and the timely acquisition of additional resources.

## Idaho Falls

| Idaho Falls Lateral Design Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 7,627,586 | 7,716,508 | 7,745,989 | 7,829,779 | 7,902,372 |
| Base | 7,637,078 | 7,828,935 | 7,970,454 | 8,169,133 | 8,365,591 |
| High | 7,655,847 | 8,009,918 | 8,326,093 | 8,707,370 | 9,081,898 |

| Idaho Falls Lateral Normal Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 6,730,207 | 6,783,602 | 6,832,398 | 6,905,230 | 6,967,897 |
| Base | 6,738,832 | 6,882,202 | 7,030,014 | 7,203,941 | 7,375,543 |
| High | 6,756,067 | 7,041,635 | 7,344,133 | 7,679,063 | 8,007,397 |

## Sun Valley

| Sun Valley Lateral Design Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 1,778,142 | 1,785,179 | 1,787,931 | 1,797,763 | 1,802,295 |
| Base | 1,779,198 | 1,798,889 | 1,815,620 | 1,839,560 | 1,857,106 |
| High | 1,782,568 | 1,828,409 | 1,875,123 | 1,928,355 | 1,974,975 |

| Sun Valley Lateral Normal Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 1,533,044 | 1,539,473 | 1,540,492 | 1,546,325 | 1,552,436 |
| Base | 1,533,969 | 1,551,418 | 1,564,226 | 1,582,102 | 1,599,410 |
| High | 1,536,935 | 1,576,715 | 1,615,327 | 1,658,094 | 1,700,365 |

## Canyon County

| Canyon County Area Design Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 5,734,422 | 5,856,472 | 5,980,595 | 6,170,659 | 6,304,365 |
| Base | 5,740,449 | 5,909,851 | 6,079,751 | 6,330,211 | 6,516,580 |
| High | 5,754,393 | 6,014,916 | 6,283,378 | 6,626,757 | 6,908,318 |

| Canyon County Area Normal Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 4,902,423 | 5,007,181 | 5,109,727 | 5,291,547 | 5,382,113 |
| Base | 4,907,883 | 5,053,670 | 5,194,864 | 5,428,483 | 5,564,277 |
| High | 4,920,743 | 5,144,079 | 5,370,383 | 5,685,223 | 5,900,981 |

## State Street

| State Street Lateral Design Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 5,766,073 | 5,819,922 | 5,856,276 | 5,915,777 | 5,970,645 |
| Base | 5,773,038 | 5,896,192 | 6,001,183 | 6,137,696 | 6,272,411 |
| High | 5,791,690 | 6,070,167 | 6,350,558 | 6,661,942 | 6,972,532 |

| State Street Lateral Normal Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 4,717,736 | 4,762,209 | 4,788,669 | 4,835,870 | 4,879,128 |
| Base | 4,723,812 | 4,825,139 | 4,906,782 | 5,016,541 | 5,124,500 |
| High | 4,739,867 | 4,966,638 | 5,191,325 | 5,443,094 | 5,693,692 |

## Central ADA Area

| Central ADA Area Design Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 5,991,595 | 6,052,025 | 6,095,500 | 6,164,758 | 6,228,485 |
| Base | 6,000,978 | 6,144,171 | 6,270,313 | 6,431,530 | 6,591,090 |
| High | 6,021,878 | 6,349,402 | 6,681,334 | 7,048,156 | 7,414,537 |

| Central ADA Area Normal Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 5,262,893 | 5,316,849 | 5,352,165 | 5,411,860 | 5,466,557 |
| Base | 5,271,573 | 5,398,229 | 5,505,377 | 5,645,452 | 5,783,814 |
| High | 5,290,860 | 5,577,899 | 5,865,210 | 6,184,912 | 6,503,739 |

**Total Company**

| Total Company Design Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 41,519,017 | 41,914,064 | 42,255,429 | 42,741,278 | 43,205,947 |
| Base | 41,569,412 | 42,431,429 | 43,245,182 | 44,253,064 | 45,249,414 |
| High | 41,679,215 | 43,434,592 | 45,251,473 | 47,259,310 | 49,250,777 |

| Total Company Normal Weather- Total Annual Usage (Dth) | | | | | |
|---|---|---|---|---|---|
| Growth Scenario | 2015 | 2016 | 2017 | 2018 | 2019 |
| Low | 35,168,886 | 35,600,981 | 35,773,397 | 36,174,671 | 36,556,680 |
| Base | 35,213,766 | 36,022,659 | 36,610,031 | 37,451,448 | 38,281,143 |
| High | 35,311,408 | 36,893,679 | 38,306,562 | 39,991,408 | 41,659,446 |

## Projected Capacity Deficits - All Scenarios

Residential, commercial and industrial peak day load growth on Intermountain's system is forecast over the five-year period to grow at an average annual rate of .91% (low growth), 1.82% (base case) and 3.41% (high growth), highlighting the need for long-term planning. As this section illustrates, there are no projected capacity deficits during the IRP planning horizon.

## Idaho Falls Lateral LDC Study

When forecast peak day sendout on the Idaho Falls lateral is matched against the existing peak day distribution capacity (95,800 Dth) in the base price scenario, a peak day delivery deficit does occur.

**IFL - Design Weather Peak Day Deficit Under Existing Resources (Dth)**

| Scenario/Year | 2 015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| Low Growth | 0 | 0 | 0 | 0 | 0 |
| Base Growth | 0 | 0 | 0 | 1,583 | 3,498 |
| High Growth | 0 | 0 | 2,837 | 6,377 | 9,931 |

## Sun Valley Lateral LDC Study

When forecasted peak day send out on the Sun Valley Lateral is matched against the existing peak day distribution capacity (20,200 Dth), a peak day delivery deficit does occur.

**SVL - Design Weather Peak Day Deficit Under Existing Resources (Dth)**

| Scenario/Year | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| Low Growth | 0 | 0 | 0 | 0 | 0 |
| Base Growth | 0 | 0 | 0 | 0 | 0 |
| High Growth | 0 | 0 | 0 | 0 | 0 |

## Canyon County LDC Study

When forecasted peak day send out for the Canyon County region is matched against the existing peak day distribution capacity (79,000 Dth), a peak day delivery deficit does occur.

**CC Area - Design Weather Peak Day Deficit Under Existing Resources (Dth)**

| Scenario/Year | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| Low Growth | 0 | 0 | 0 | 0 | 0 |
| Base Growth | 0 | 0 | 0 | 0 | 0 |
| High Growth | 0 | 0 | 0 | 0 | 836 |

## State Street Lateral LDC Study

When forecasted peak day send out for the State Street Lateral is matched against the existing peak day distribution capacity (69,500 Dth), a peak day delivery deficit does occur.

**SSL - Design Weather Peak Day Deficit Under Existing Resources (Dth)**

| Scenario/Year | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| Low Growth | 0 | 0 | 0 | 0 | 0 |
| Base Growth | 0 | 0 | 0 | 0 | 0 |
| High Growth | 0 | 0 | 0 | 0 | 2,213 |

## Central Ada Area LDC Study

When forecasted peak day send out for the Central Ada Area is matched against the existing peak day distribution capacity (62,500 Dth through 2016 & 70,200 thereafter), a peak day delivery deficit does occur.

**CCA - Design Weather Peak Day Deficit Under Existing Resources (Dth)**

| Scenario/Year | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| Low Growth | 0 | 0 | 0 | 0 | 0 |
| Base Growth | 0 | 0 | 0 | 0 | 0 |
| High Growth | 0 | 1,562 | 0 | 1,387 | 5,343 |

## Total Company LDC Study

The Total Company perspective differs from the laterals in that it reflects the amount of gas that can be delivered to Intermountain via the various resources on the interstate system. Hence, total system deliveries should provide at least the net sum demand – or the total available distribution capacity where applicable - of all the laterals/areas on the distribution system. The following table shows that there are no annual peak day deficits based on existing resources:

**Total Company – Design Weather Peak Day Surplus/(Deficit) Under Existing Resources (Dth)**

| Scenario/Year | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| Low Growth | 100,169 | 96,566 | 92,307 | 87,153 | 82,093 |
| Base Growth | 100,053 | 92,038 | 83,054 | 72,905 | 62,676 |
| High Growth | 99,774 | 82,720 | 64,343 | 44,668 | 24,846 |

## Total Company Design Weather/Base Growth 2014 IRP vs. 2012 IRP Usage Comparison

Table 2.1

**2014 IRP LOAD DEMAND CURVE - TOTAL COMPANY USAGE DESIGN BASE CASE**
(Volumes in Therms)

| | NWP Firm Transport Capacity | Peak Day Sendout: Core Market | Peak Day Sendout: Industrial Firm CD[1] | Peak Day Sendout: Total |
|---|---|---|---|---|
| 2015 | 2,813,450 | 3,842,900 | 1,168,870 | 5,011,770 |
| 2016 | 2,813,450 | 3,928,440 | 1,275,170 | 5,203,610 |
| 2017 | 2,813,450 | 4,018,280 | 1,275,170 | 5,293,450 |

[1]Future growth in transport CD is limited to T-4, which does not affect Intermountain's interstate pipeline capacity requirements.

Table 2.2

**2012 IRP LOAD DEMAND CURVE - TOTAL COMPANY USAGE DESIGN BASE CASE**
(Volumes in Therms)

| | NWP Firm Transport Capacity | Peak Day Sendout: Core Market | Peak Day Sendout: Industrial Firm CD[1] | Peak Day Sendout: Total |
|---|---|---|---|---|
| 2015 | 2,651,950 | 3,671,920 | 1,461,130 | 5,133,050 |
| 2016 | 2,571,390 | 3,720,820 | 1,461,130 | 5,181,950 |
| 2017 | 2,571,390 | 3,769,680 | 1,461,130 | 5,230,810 |

[1]Future growth in transport CD is limited to T-4, which does not affect Intermountain's interstate pipeline capacity requirements.

Table 2.3

**2014 IRP LOAD DEMAND CURVE - TOTAL COMPANY DESIGN BASE CASE**
**Over/(Under) 2012 IRP**
(Volumes in Therms)

| | NWP Firm Transport Capacity | Peak Day Sendout Core Market | Industrial Firm CD[1] | Total |
|---|---|---|---|---|
| 2015 | 161,500 | 170,980 | -292,260 | -121,280 |
| 2016 | 242,060 | 207,620 | -185,960 | 21,600 |
| 2017 | 242,060 | 248,600 | -185,960 | 62,640 |

[1]Future growth in transport CD is limited to T-4, which does not affect Intermountain's interstate pipeline capacity requirements.

## Total Company Peak Day Deliverability Comparison for 2014 IRP vs. 2012 IRP

Table 3.1

**2014 IRP PEAK DAY FIRM DELIVERY CAPABILITY**
(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| **Maximum Daily Storage Withdrawals:** | | | |
| **Nampa LNG** | 600,000 | 600,000 | 600,000 |
| **Plymouth LS** | 1,132,000 | 1,132,000 | 1,132,000 |
| **Jackson Prairie SGS** | 303,370 | 303,370 | 303,370 |
| **Total Storage** | 2,035,370 | 2,035,370 | 2,035,370 |
| **Maximum Deliverability (NWP)** | 2,813,450 | 2,813,450 | 2,813,450 |
| **Total Peak Day Deliverability** | 4,848,820 | 4,848,820 | 4,848,820 |

Table 3.2

**2012 IRP PEAK DAY FIRM DELIVERY CAPABILITY**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| **Maximum Daily Storage Withdrawals:** | | | |
| **Nampa LNG** | 600,000 | 600,000 | 600,000 |
| **Plymouth LS** | 1,132,000 | 1,132,000 | 1,132,000 |
| **Jackson Prairie SGS** | 303,370 | 303,370 | 303,370 |
| **Total Storage** | 2,035,370 | 2,035,370 | 2,035,370 |
| **Maximum Deliverability (NWP)** | 2,736,250 | 2,728,740 | 2,699,590 |
| **Total Peak Day Deliverability** | 4,771,620 | 4,764,110 | 4,734,960 |

Table 3.3

**2014 IRP PEAK DAY FIRM DELIVERY CAPABILITY**

**Over/(Under) 2012 IRP**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| **Maximum Daily Storage Withdrawals:** | | | |
| **Nampa LNG** | 0 | 0 | 0 |
| **Plymouth LS** | 0 | 0 | 0 |
| **Jackson Prairie SGS** | 0 | 0 | 0 |
| **Total Storage** | 0 | 0 | 0 |
| **Maximum Deliverability (NWP)** | 77,200 | 84,710 | 113,860 |

## Total Company Peak Delivery Deficit for 2014 IRP vs. 2012 IRP

Table 4.1

**2014 IRP FIRM DELIVERY DEFICIT – TOTAL COMPANY DESIGN BASE CASE**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit | 93.340 | 181,790 | 271,630 |
| Total Winter Deficit[1] | 93,340 | 181,790 | 353,250 |
| Days Requiring Additional Resources | 1 | 1 | 4 |

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

Table 4.2

**2012 IRP FIRM DELIVERY DEFICIT – TOTAL COMPANY DESIGN BASE CASE**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit | 0 | 0 | 0 |
| Total Winter Deficit[1] | 0 | 0 | 0 |
| Days Requiring Additional Resources | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

## Idaho Falls Lateral Design Weather/Base Growth Comparison for 2014 IRP vs. 2012 IRP

Table 5.1

**2014 LOAD DEMAND CURVE - IDAHO FALLS DESIGN BASE CASE**
(Volumes in Therms)

| | | Peak Day Sendout | | |
|---|---|---|---|---|
| | **Existing Distribution Transport Capacity** | **Core Market** | **Industrial Firm CD[1]** | **Total** |
| **2015** | 958,000 | 687,513 | 234,700 | 922,213 |
| **2016** | 958,000 | 702,256 | 234,700 | 936,956 |
| **2017** | 958,000 | 720,085 | 234,700 | 954,785 |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

Table 5.2

**2012 LOAD DEMAND CURVE - IDAHO FALLS DESIGN BASE CASE**
(Volumes in Therms)

| | | Peak Day Sendout | | |
|---|---|---|---|---|
| | **Existing Distribution Transportation Capacity** | **Core Market** | **Industrial Firm CD[1]** | **Total** |
| **2015** | 987,000 | 672,116 | 239,550 | 911,666 |
| **2016** | 987,000 | 682,275 | 239,550 | 921,825 |
| **2017** | 987,000 | 692,409 | 239,550 | 931,959 |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

Table 5.3

**2014 LOAD DEMAND CURVE - IDAHO FALLS DESIGN BASE CASE**

**Over/(Under) 2012 IRP**
(Volumes in Therms)

| | | | Peak Day Sendout | |
|---|---|---|---|---|
| | Existing Distribution Transport Capacity | Core Market | Industrial Firm CD[1] | Total |
| **2015** | -29,000 | 15,397 | -4,850 | 10,547 |
| **2016** | -29,000 | 19,981 | -4,850 | 15,131 |
| **2017** | -29,000 | 27,676 | -4,850 | 22,826 |

[1]Existing firm contract demand includes LV -1, T-5, and T-4 requirements.

## Idaho Falls Lateral Delivery Deficit Comparison for 2014 IRP vs. 2012 IRP

Table 6.1

**2014 IRP FIRM DELIVERY DEFICIT - IDAHO FALLS DESIGN BASE CASE**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 6.2

**2012 IRP FIRM DELIVERY DEFICIT - IDAHO FALLS DESIGN BASE CASE**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 6.3

**2014 IRP FIRM DELIVERY DEFICIT - IDAHO FALLS DESIGN BASE CASE**

**Over/(Under) 2012 IRP**
(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

## Sun Valley Lateral Design Weather/Base Growth Comparison for 2014 IRP vs. 2012 IRP

Table 7.1

### 2014 IRP LOAD DEMAND CURVE - SUN VALLEY DESIGN BASE CASE

(Volumes in Therms)

| | Existing Distribution Transport Capacity | Peak Day Sendout | | |
|---|---|---|---|---|
| | | Core Market | Industrial Firm CD[1] | Total |
| **2015** | 202,000 | 161,750 | 13,350 | 175,100 |
| **2016** | 202,000 | 163,516 | 13,350 | 176,866 |
| **2017** | 202,000 | 165,697 | 13,350 | 179,047 |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

Table 7.2

**2012 IRP LOAD DEMAND CURVE - SUN VALLEY DESIGN BASE CASE**

(Volumes in Therms)

| Existing | Distribution Transport Capacity | Peak Day Sendout: Core Market | Industrial Firm CD[1] | Total |
|---|---|---|---|---|
| **2015** | 204,000 | 167,562 | 8,150 | 175,712 |
| **2016** | 204,000 | 169,317 | 8,150 | 177,467 |
| **2017** | 204,000 | 171,013 | 8,150 | 179,163 |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

Table 7.3

**2012 IRP LOAD DEMAND CURVE - SUN VALLEY DESIGN BASE CASE**

**Over/(Under) 2010 IRP**

(Volumes in Therms)

| Existing | Distribution Transport Capacity | Peak Day Sendout: Core Market | Industrial Firm CD[1] | Total |
|---|---|---|---|---|
| **2015** | (2,000) | (5,812) | 5,200 | (612) |
| **2016** | (2,000) | (5,801) | 5,200 | (601) |
| **2017** | (2,000) | (5,316) | 5,200 | (116) |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

## Sun Valley Lateral Delivery Deficit Comparison for 2014 IRP vs. 2012 IRP

Table 8.1

**2014 IRP FIRM DELIVERY DEFICIT - SUN VALLEY DESIGN BASE CASE**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 8.2

**2012 IRP FIRM DELIVERY DEFICIT - SUN VALLEY DESIGN BASE CASE**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 8.3

**2014 IRP FIRM DELIVERY DEFICIT - SUN VALLEY DESIGN BASE CASE**

**Over/(Under) 2012 IRP**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

## Canyon County Area Design Weather/Base Growth Comparison for 2014 IRP vs. 2012 IRP

Table 9.1

### 2014 LOAD DEMAND CURVE - CANYON COUNTY DESIGN BASE CASE

(Volumes in Therms)

| | Existing Distribution Transport Capacity | Peak Day Sendout | | |
|---|---|---|---|---|
| | | Core Market | Industrial Firm CD[1] | Total |
| **2015** | 790,000 | 555,797 | 126,510 | 682,307 |
| **2016** | 790,000 | 571,994 | 126,510 | 698,504 |
| **2017** | 790,000 | 590,660 | 126,510 | 717,170 |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

Table 9.2

**2012 LOAD DEMAND CURVE - CANYON COUNTY DESIGN BASE CASE**

(Volumes in Therms)

| | Existing Distribution Transport Capacity | Peak Day Sendout Core Market | Industrial Firm CD[1] | Total |
|---|---|---|---|---|
| **2015** | 680,000 | 527,575 | 93,310 | 620,885 |
| **2016** | 680,000 | 537,794 | 93,310 | 631,104 |
| **2017** | 680,000 | 548,841 | 93,310 | 642,151 |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

Table 9.3

**2014 LOAD DEMAND CURVE - CANYON COUNTY DESIGN BASE CASE**

**Over/(Under) 2012 IRP**

(Volumes in Therms)

| | Existing Distribution Transport Capacity | Peak Day Sendout Core Market | Industrial Firm CD[1] |
|---|---|---|---|
| **2015** | 110,000 | 28,222 | 33,200 |
| **2016** | 110,000 | 34,200 | 33,200 |
| **2017** | 110,000 | 41,819 | 33,200 |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

## Canyon County Area Firm Delivery Deficit Comparison for 2014 IRP vs. 2012 IRP

Table 10.1

### 2014 IRP FIRM DELIVERY DEFICIT - CANYON COUNTY DESIGN BASE CASE

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 10.2

### 2012 IRP FIRM DELIVERY DEFICIT - CANYON COUNTY DESIGN BASE CASE

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 10.3

**2014 IRP FIRM DELIVERY DEFICIT - CANYON COUNTY DESIGN BASE CASE**

**Over/(Under) 2012 IRP**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1] Equal to the total winter sendout in excess of distribution capacity.

## State Street Area Design Weather/Base Growth Comparison for 2014 IRP vs. 2012 IRP

Table 11.1

### 2012 LOAD DEMAND CURVE – STATE STREET DESIGN BASE CASE

(Volumes in Therms)

| | Existing Distribution Transport Capacity | Peak Day Sendout | | |
|---|---|---|---|---|
| | | Core Market | Industrial Firm CD[1] | Total |
| **2015** | 644,000 | 574,021 | 16,700 | 590,721 |
| **2016** | 644,000 | 586,071 | 16,700 | 602,771 |
| **2017** | 695,000 | 598,735 | 16,700 | 615,435 |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

Table 11.2

**2012 LOAD DEMAND CURVE – STATE STREET DESIGN BASE CASE**

(Volumes in Therms)

| | Existing Distribution Transport Capacity | Peak Day Sendout: Core Market | Peak Day Sendout: Industrial Firm CD[1] | Peak Day Sendout: Total |
|---|---|---|---|---|
| **2015** | 585,000 | 510,729 | 16,000 | 526,729 |
| **2016** | 585,000 | 515,755 | 16,000 | 531,755 |
| **2017** | 585,000 | 520,803 | 16,000 | 536,803 |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

Table 11.3

**2014 LOAD DEMAND CURVE – STATE STREET DESIGN BASE CASE**

**Over/(Under) 2012 IRP**

(Volumes in Therms)

| | Existing Distribution Transport Capacity | Peak Day Sendout: Core Market | Peak Day Sendout: Industrial Firm CD[1] | Peak Day Sendout: Total |
|---|---|---|---|---|
| **2015** | 59,000 | 63,292 | 700 | 63,992 |
| **2016** | 59,000 | 70,316 | 700 | 71,016 |
| **2017** | 110,000 | 77,932 | 700 | 78,632 |

[1]Existing firm contract demand includes LV-1, T-5, and T-4 requirements.

## State Street Area Firm Delivery Deficit Comparison for 2014 IRP vs. 2012 IRP

Table 12.1

**2014 IRP FIRM DELIVERY DEFICIT – STATE STREET DESIGN BASE CASE**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 12.2

**2012 IRP FIRM DELIVERY DEFICIT – STATE STREET DESIGN BASE CASE**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

Table 12.3

**2014 IRP FIRM DELIVERY DEFICIT – STATE STREET DESIGN BASE CASE**

**Over/(Under) 2012 IRP**

(Volumes in Therms)

| | 2015 | 2016 | 2017 |
|---|---|---|---|
| Peak Day Deficit[1] | 0 | 0 | 0 |
| Total Winter Deficit | 0 | 0 | 0 |
| Days Requiring Additional Capacity | 0 | 0 | 0 |

[1]Equal to the total winter sendout in excess of distribution capacity.

## Intermountain Gas Company

### 2014 IRP Firm Receipt Point Capacity Through 2017

### Volumes in MMBtu

| Receipt Point | 2015 | 2016 | 2017 |
|---|---|---|---|
| Sumas | 17,291 | 17,291 | 17,291 |
| Stanfield | 158,670 | 158,670 | 158,670 |
| Rockies | 84,328 | 84,328 | 84,328 |
| Storage | 143,537 | 143,537 | 143,537 |
| Citygate | 18,056 | 18,056 | 18,056 |
| Total | 421,882 | 421,882 | 421,882 |

## Intermountain Gas Company

### 2012 IRP Firm Receipt Point Capacity Through 2017

### Volumes in MMBtu

| Receipt Point | 2015 | 2016 | 2017 |
|---|---|---|---|
| Sumas | 27,832 | 27,832 | 27,832 |
| Stanfield | 152,035 | 158,979 | 158,979 |
| Rockies | 70,328 | 70,328 | 70,328 |
| Storage | 194,854 | 194,854 | 194,854 |
| Citygate | 15,000 | 0 | 0 |
| Total | 460,049 | 451,993 | 451,993 |

**Intermountain Gas Company**

**2014 IRP Firm Receipt Point Capacity Through 2017**

**Over/ (Under) 2012 IRP**

**Volumes in MMBtu**

| Receipt Point | 2015 | 2016 | 2017 |
|---|---|---|---|
| Sumas | (10,541) | (10,541) | (10,541) |
| Stanfield | 6,635 | (309) | (309) |
| Rockies | 14,000 | 14,000 | 14,000 |
| Storage | (51,317) | (51,317) | (51,317) |
| Citygate | 3,056 | 18,056 | 18,056 |
| Total | (38,167) | (30,111) | (30,111) |

# NON-UTILITY LNG SALES

Intermountain completed construction of a liquefied natural gas (LNG) storage plant in Nampa, Idaho in 1974. The plant is designed to liquefy natural gas into LNG and vaporize the LNG for use in the company's distribution system. The plant design also includes a 7 million gallon for LNG storage. The Nampa plant is utilized as the top of the supply stack for peak natural gas usage periods meaning that it is the supply of last resort. Consequently, LNG is generally vaporized during periods of design weather. The company's IRP is used to forecast projected withdrawals under design weather scenarios. The company recognized that due to warming weather trends beginning in the 1990's, the occurrence of design weather was experienced less than in prior years.

The company built a satellite LNG facility in 2007 near Rexburg, Idaho to help provide Peak Day gas supplies to the northern end of the Idaho Falls lateral in peak usage periods. Because the Rexburg facility does not have the capability to liquefy, LNG must be trucked into the facility to store it in on-site storage tanks or be directly injected into the IF lateral.

In the early years of operation, Intermountain purchased LNG from suppliers who obtained LNG from sources in southwestern Wyoming. By 2010, those same suppliers indicated difficulty in obtaining firm LNG supply particularly during peak weather events. The lack of LNG during peak load periods would limit the usefulness of the Rexburg facility and perhaps lead to undesired pressure drops in the lateral. Consequently Intermountain determined that the best long-term solution was to build a truck loading station at the Nampa plant to enable the company to ship LNG directly from the Nampa plant to the Rexburg facility. The truck loading station allowed Intermountain to directly control the supply of LNG to Rexburg.

During this same time period, Intermountain began to receive inquiries as to the possibility of providing LNG to non-utility truck and other industrial markets. The company recognized that the large LNG storage tank and the new truck loading station provided a mechanism whereby the company could serve a growing market need by providing non-peak LNG supplies to non-utility customers. At the same time the increased usage of the LNG facility could provide a direct benefit to Intermountain's customers.

Consequently, Intermountain requested authority to sell excess LNG to non-utility customers in January 2013 through INT G-13-02. The Commission granted Intermountain authority to do so in April 2013. The first load delivered to a non-utility customer occurred in June 2013. Non-utility sales grew slowly through the remainder of 2013

Intermountain's customers benefit from Intermountain's LNG sales activities in several different ways. First, Intermountain continues to defer 2.5¢ per gallon into a capital account and amortizes that balance as it identifies capital costs that increased use of the Nampa facility. That procedure directly reduces both rate base and depreciation expense. Intermountain's customers also benefit from the 50/50 margin sharing mechanism that applies credits directly to the company's 191 account to offset gas purchase costs. The Case filed in August 2014 included approximately $400,000 of credits which helped to lower the company's WACOG through September 2015.

Intermountain continues to see growth in non-utility LNG sales and believes that because the program helps spur a new and growing market, increases the use of Nampa LNG plant while demonstrating cost savings to Intermountain's customer that the non-utility sales program should continue.